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October 31, 2023

VIA RESS AND EMAIL

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2023-0092
2022 Utility Earnings and Disposition of Deferral & Variance Account Balances – Interrogatory Responses

In accordance with the OEB's Procedural Order No. 1 dated, August 3, 2023, enclosed please find the interrogatory responses of Enbridge Gas.

In the event that you have any questions on the above or would like to discuss in more detail, please do not hesitate to contact me.

Sincerely,

(Original Digitally Signed)

Richard Wathy
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)
EB-2023-0092 Intervenors

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Utility O&M Exhibit B, Tab 3, Schedule 1, pp. 1-7

Preamble:

In the discussion on utility O&M expenses, Enbridge Gas stated that O&M expenses increased by $81.7 million, primarily due to increases in Corporate Shared Services (CSS), Outside Services, Admin Expenses, and Miscellaneous Expenses.

Question(s):

a) The increase of $81.7 million in O&M expenses from 2021-2022 is substantial in comparison to previous years. Please confirm whether Enbridge Gas expects this trend to continue or decrease.

b) Please provide additional reasoning for why Travel and Entertainment expenses increased by 119.6% from 2021-2022.

c) Please provide detailed costs under the Corporate Shared Services category, including the cost allocation methodology that was used to assign costs to the individual business units.

d) What were the main drivers of the 38.3% decrease in Integration-Related costs?

e) Please provide additional explanation of other economic factors mentioned as a driver for the increase in Miscellaneous expenses.

Response:

a) As noted in EB-2022-0200, Exhibit 4, Tab 4, Schedule 2, Table 1, 2023 O&M is forecasted at $1,022 million which is $20 million higher than 2022. The key drivers of increases from 2022 to 2023 are bad debt, pension costs and TIS costs related to migration to ‘as a service’ models to enhance technology reliability and training, change management and sustainment associated with harmonized systems. Lower integration-related costs, as initiatives are closed out, will partially alleviate overall cost pressures.

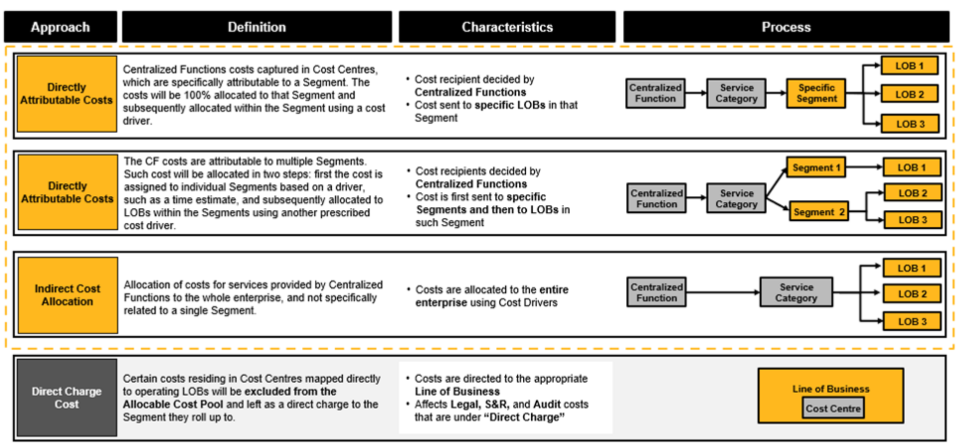
b) The travel and entertainment expenses increase in 2022 were due to the lifting of COVID-19 restrictions resulting in higher travel and employee related expenses.

c) Please see details of CSS cost breakdown in Table 1 below.

As described in EB-2020-0200, Exhibit 4, Tab 4, Schedule 3, paragraph 48:

> The costs of Corporate Functions (CF), known as CF costs, are allocated among Enbridge affiliates based on the internally developed CFCAM as provided in Figure 1. The CFCAM can be found in the Intercorporate Services Agreement (ISA). CF costs are collected in cost centres which are then grouped into service categories within a CF. A service category represents a grouping of CF cost centres into “like” services which form a total cost pool that is ultimately allocated to individual lines of business (LOBs)[1] as CF costs. These allocations are based on the principle of cost causation using cost drivers, where costs are driven by the activities required to provide the service.

Figure 1: CFCAM



For more details on the cost allocation methodology that was used to assign costs to the individual business units please refer to EB-2020-0200, Exhibit 4, Tab 4, Schedule 3, Section 2.2 CFCAM.

[1] LOBs represent subdivisions within a segment. Segments are Enbridge’s core businesses, comprised of: Liquids Pipelines, Gas Transmission & Midstream, Gas Distribution & Storage, Renewable Power Generation, Energy Services and Eliminations & Other. Enbridge Gas belongs to the Gas Distribution & Storage segment. Synonymous with business unit as described in the ISA.

Table 1
Detail cost breakdown of CSS (line 13)
Central Functions O&M

Line No.	Particulars ($ millions)	2022 Actual
1	Aviation	0.0
2	CDO	3.5
3	EAWM	1.6
4	Executive	0.8
5	Finance	32.8
6	REWS	24.6
7	HR	22.9
8	Legal	14.6
9	PAC	6.5
10	S&R	10.1
11	SCM	11.7
12	TIS	100.0
13	Benefits	103.6
14	Depreciation	21.6
15	Insurance	9.2
16	CF costs	363.5
17	Capitalization on CSS	(86.7)
18	Utility CF adjustment (removed in line 22 of table 1)	8.4
	Total CSS(Table 1, line 13)	285.2

d) The main driver of the decrease in Integration-Related costs is the winddown of integration activities and initiatives such as completion of CIS consolidation project. By the end of 2023 integration related costs will be eliminated.

e) Miscellaneous Expense (Line 16) increased $6.6 million over the prior year primarily due to increase in bad debt. Other economic factors refer to the state of the broader economy, including unemployment rates, inflation, interest rates and consumer confidence. These conditions impact job availability, wages and the cost of goods and services which in turn can affect the ability to pay bills.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Enbridge Gas - Accounting Policy Changes Deferral Account Exhibit C, Tab 1, p. 2

Preamble:

Enbridge Gas continues to track the annual revenue requirement impact of accounting policy changes made as of the amalgamation date, January 1, 2019, as well as any further accounting policy changes adopted since that time.

Question(s):

a) Please identify any accounting policy changes made in 2022 that are in addition to those made in 2019-2021.

b) Please provide details of any additional changes and the potential impact of those changes on the balances in the APCDA.

Response:

a) As noted in Exhibit C, Tab 1, pages 7 and 8, in 2022 Enbridge Gas implemented financial system harmonization for recognition of gas costs in the general ledger. This harmonization, the related rationale, and resulting impacts have been discussed in detail through Enbridge Gas's 2024 Rebasing proceeding[1].

b) As provided in Exhibit C, Tab 1, page 8, Enbridge Gas recorded $62.155 million in the APCDA as a receivable recoverable from ratepayers. Enbridge Gas further explained the rationale as follows:

> The amount transferred to the APCDA represents costs incurred by Enbridge Gas in providing service to customers and does not reflect any change to the total annual revenue requirement of Enbridge Gas to provide gas supply storage and transportation service. The change in the accounting treatment does recognize a one-time transition to allow for consistent recovery of these gas supply storage and transportation costs for Enbridge Gas.[2]

[1] EB-2022-0200, Exhibit 9, Tab 2, Schedule 1, pp. 14-16; and Exhibit I.ADR.44 plus Attachment.
[2] EB-2022-0200, Exhibit 9, Tab 2, Schedule 1, p. 8 (June 14, 2023).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Enbridge Gas - Tax Variance Deferral Account Exhibit C, Tab 1, Schedule 1, pp. 12-14

Preamble:

Consistent with the OEB's EB-2021-0149 Decision and Order, dated January 27, 2021, the Tax Variance Deferral Account balance also includes balances that relate to accelerated CCA impacts of capital additions related to amalgamation/integration capital projects. The 2022 balance for amalgamation/integration projects is a credit of $6.883 million.

Question(s):

a) Please provide a table identifying the specific projects categorized as amalgamation/integration spending and the accelerated CCA amount associated with each project.

b) Please also provide the reasons for classifying these projects as amalgamation/integration related capital spending.

c) Please confirm if Enbridge Gas funded amalgamation/integration capital projects in 2022 through synergies. If yes, please establish a link between the achieved synergies and the related amalgamation/integration projects.

Response:

a) In EB-2022-0200, Exhibit J15.1, Attachment 2, page 3, Enbridge Gas provided the accelerated CCA impacts related to 2022 Actual amalgamation/integration related projects. The CCA Pool additions related to these projects totaled $34.3 million as noted in column (a), line 43 of that exhibit with a corresponding accelerated CCA versus regular CCA impact of $6.2 million payable recorded in the TVDA for 2022 (column g, line 52). The offsetting $13.1 million receivable, to achieve the net receivable of $6.9 million recognized in 2022, pertains to the reversal/residual effects of projects added in 2020 and 2021 (column g, line 39). The specific projects categorized as amalgamation/integration in 2022 were described in EB-2022-0200, Exhibit 1, Tab 9, Schedule 1, Attachment 1.

b) As noted previously in EB-2022-0110, Exhibit I.STAFF.3, page 2:

> Enbridge Gas continues to evaluate projects to determine whether they meet the criteria of integration capital: a one-time incremental cost related to the amalgamation of EGD and Union. Projects can be newly identified to address integration needs, or they may be driven by a need to replace an asset due to obsolescence. In either case, the project is classified as integration as it drives a harmonized solution that adds value to the integrated utility. It's important to note that the work being addressed through some integration projects would have been required for either or both rate zones in the absence of amalgamation (because of factors such as obsolescence or growth), but the projects are nonetheless included as integration capital because the project supports the amalgamated utility.

Enbridge Gas continued this approach through 2022 and each of the projects that went into service in 2022 and as referenced in EB-2022-0200, Exhibit J15.1, Attachment 2, page 3 were determined to have met the criteria noted. This was further reiterated in EB-2022-0200 Oral Hearing where Enbridge Gas agreed with and confirmed the following: "(A)n integration project, capital project … defined as expenditures required to integrate Enbridge Gas and Union Gas under common system process facilities."[1] Further, "integrate the companies, they also extended the useful life of those assets and they also will benefit into the future."[2]

c) Again, as noted previously in EB-2022-0110, Exhibit I.STAFF.3, page 2

> During the deferred rebasing period, Enbridge Gas is leveraging amalgamation/ integration synergies derived from initiatives to fund, in whole or in part, the annual costs related to amalgamation/integration capital (and amalgamation/integration period charges). This is premised on the fact that during the deferred rebasing term, Enbridge Gas retains the benefits from amalgamation, but also pays the associated costs (the benefits follow the costs principle). It is further evidenced by the fact that capital related to amalgamation/integration capital projects has been excluded from the capital forecasts utilized to determine Incremental Capital Module (ICM) eligible capital amounts over the deferred rebasing term. As a result, funding for such projects is not provided through ICM rates for capital amounts above the ICM threshold, nor is it provided through base rates (i.e., they are not pushing other capital projects above the ICM threshold).
>
> The Company notes that each individual amalgamation/integration capital project may or may not be funded, in whole or in part, by savings it creates over the deferred rebasing term. Certain individual projects may not generate synergies/savings but it does support amalgamation. For projects that do result in savings, the realization of those savings may not occur until after the project has gone into service. As such, at any point in time over the deferred rebasing term, costs for an individual project may be occurring without the realization of savings to that point.

[1]EB-2022-0200, Transcript Volume 14, p. 177.
[2]EB-2022-0200, Transcript Volume 14, p. 147.

The above has held true through 2022 and was further reiterated in EB-2022-0200 Oral hearing where Enbridge Gas stated: "(T)his capital investment that has occurred through the deferred rebasing period has been funded by the synergies generated by the integration and the system improvements made."[3]

[3] EB-2022-0200, Transcript Volume 14, p. 149.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

2022 Storage & Transportation Deferral Account - EGD Exhibit D, Tab 1, p. 2

Preamble:

The balance in the 2022 S&TDA that the Company is proposing to collect from customers is $8.1 million plus interest. The primary driver for the balance in the 2022 S&TDA is higher than forecasted transportation prices and higher than forecasted market-based storage costs in 2022, partially offset by a $1.5 million refund from the Union rate zone as part of Union's 2020 deferral disposition.

Question(s):

a) Please provide the average market-based storage costs for 2021 and 2022.

b) Why have market-based storage costs increased in 2022?

Response:

a) The market-based storage costs for 2021 and 2022 are $22.4 million and $21.4 million respectively. The average storage costs for 2021 and 2022 are $0.85/GJ and $0.82/GJ respectively.

b) The reduction in 2022 market-based storage costs relative to 2021 is driven by lower storage prices. The market-based storage costs for 2022 are higher than the 2018 OEB-approved forecast by $1.3 million, driven by an increase to in-franchise storage requirements for EGD rate zone customers[1] of approximately $1.4 million, partly offset by the lower average storage prices in 2022 relative to the 2018 forecast of approximately $0.1 million.

[1] In Enbridge Gas's 2018 Rates Application the utility described its strategy to acquire 2-3 PJ of incremental storage to cost-effectively capture the benefit of operational flexibility and reliability. See EB-2017-0086, Exhibit D1, Tab 2, Schedule 3, pp. 8, 10-11 and Exhibit D1, Tab 2, Schedule 11, p. 12.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Transactional Services Deferral Account - EGD Exhibit D, Tab 1, p. 4

Preamble:

Enbridge Gas generated a total of $47.9 million in net Transactional Services revenue in 2022, of which the ratepayer portion represents $43.1 million, through a combination of Storage and Transportation Optimization. Transactional services optimization in the Enbridge Gas rate zones is higher than what has been included in rates due to changing market dynamics. The majority of this increase results from the increase in the Dawn-Waddington spread. This spread is impacted by the lack of pipeline infrastructure serving US Northeast markets.

Question(s):

a) Please explain why Enbridge Gas was not able to optimize any storage transactions for the EGD rate zone in 2021 but generated a total of $47.9 million in net Transactional Services revenue in 2022.

b) Please provide additional information on the changing market dynamics referenced above.

c) Does Enbridge Gas expect this trend to continue in 2023?

Response:

a) Enbridge Gas was not able to optimize any storage transactions for the EGD rate zone in 2022 due to reduced demand for short term storage services.

b) Factors impacting the Dawn-Waddington spread in 2022 include demand growth in the US Northeast with no increase in pipeline capacity. European demand for LNG has increased because of the Russia-Ukraine conflict driving LNG prices higher. The US Northeast uses LNG imports as a source of natural gas supply in peak periods due to the lack of available pipeline capacity into the area. The US Northeast experienced several cold weather events driving up the price of natural gas at

Waddington for several days. Overall, the Dawn-Waddington spread was higher in the winter months of 2022 than in 2021 by more than 500% (based on the average daily settled price for the months of January, February, March, November, and December). Most of the Transportation Optimization revenue is derived based on the spread between Dawn and Waddington; this resulted in the increased revenue realized during 2022 compared to 2021.

c) Enbridge Gas expects this trend to continue in 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

2022 Unaccounted for Gas Variance Account - EGD Exhibit C, Tab 1, p. 21

Preamble:

In the EGD Rate Zone, actual UAF was determined to be 256,332 103m³. The forecast UAF volume of UAF was 106,677 103m³. The variance between actual and forecasted UAF volumes of 149,656 103m³, resulted in a debit balance of $41.4 million in the UAFVA, plus interest.
Enbridge Gas has taken the initial steps to establish a discrete team with the express mandate to investigate root causes, make recommendations to reduce and monitor, and to implement a sustainment and governance model for UFG for the utility.

Question(s):

a) The variance between forecasted and actual unaccounted for gas resulted in a substantial balance for 2022. Please explain the significant disparity between forecasted and actual UFG in 2022.

b) Please provide additional details on the status of efforts by the discrete team referenced above. What options have been developed or proposed so far to reduce UFG levels going forward?

Response:

a) & b)

The UFG team referenced, in Exhibit D, Tab 1, page 21, is currently being formed. A manager has been selected to lead the team and efforts to date have been focused on determining resource requirements to support the works described within the attached Summary Project Charter (please see Attachment 1 to this response), including: (i) development of an end-to-end understanding of UFG-related processes, data/systems, and calculation methodologies; (ii) development of a strategy to gather data on physical and non-physical sources of UFG volumes; (iii) identification, investigation, and mitigation of contributing sources of UFG; and (iv) development of long-term & sustainable cross-functional governance, monitoring, and reporting.

As the team is still being formed and because the investigation of potential contributing sources of UFG is expected to be complex, time consuming, and to involve multiple business areas, further explanation and/or quantification of contributing sources (root causes) of the 2022 variances noted are limited at this time. However, as stated in response to an interrogatory from OEB staff in the Company's 2024 Rebasing proceeding,[1] several measures noted in the UFG Progress Report and Supplemental UFG Progress Report have been implemented and others are ongoing in nature, such as:

- Meter audits between interconnecting parties, participation in industry groups and associations and regular meetings of cross-functional measurement groups.
- Work to update gas quality parameters during routine pressure regulation and measurement inspections, and to update gas quality parameters by 2025.
- Work to eliminate a backlog of leaks identified prior to the roll out of a new leak operating standard.
- Work to align applications used for large volume customer measurement to ensure consistency.
- A system application change to improve reporting underpinning unbilled sales estimates.[2]

Additionally, initial work has been completed to identify potential contributing sources of UFG for further investigation, including:

- A review of storage inventory measurement and reporting.
- A preliminary review of the potential impacts of prior period adjustments.

As noted in Exhibit D, Tab 1, page 21, in its normal course of business the Company is continuing to monitor UFG levels monthly and has recently launched some initiatives that have the potential to mitigate future UFG volumes, including but not limited to:

- actions to resolve a backlog of vacant premises where consumption has not been billed, that accumulated over the course of the COVID-19 pandemic due to a decision by Enbridge Gas to provide exceptional relief to vulnerable customers; and
- an incentive program to encourage general service customers to submit their own meter readings (from June 2023 to January 2024).

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[1] EB-2022-0200, Exhibit I.4.2-STAFF-108.
[2] Early indications are that December 2022 contract market unbilled estimate was understated and thus contributed 6,000 10^3m^3 to 2022 UFG volumes.

GDS Portfolio UFG Project Summary

Project Sponsor: Jason Gillett

VP Area: Jim Redford

Project Lead: Adam Stiers

Project Manager: TBD

PROJECT DESCRIPTION (SCOPE)

Identify, investigate, & mitigate contributing sources of unaccounted for gas (UFG), & develop long-term & sustainable cross-functional governance, monitoring, and reporting. This will both improve active mitigation & ongoing awareness of contributing sources of UFG volumes & demonstrate prudence to the Ontario Energy Board. The investigation of potential contributing sources of UFG is expected to be complex, time consuming, & to involve multiple business areas.

PROJECT VALUE: DRIVERS & BENEFITS

Drivers: Safety/ Reliability, Compliance, Efficiency/ Savings, Revenue/ Growth, Risk Reduction, Customer Experience

Since 2020, the volatility & volume of UFG has increased. The Company has been unable to attribute these volumes to specific contributing sources, & cannot explain how it will mitigate such volumes going forward. This leaves the Company at risk as 2022 UFG volumes reached nearly 300% of budgeted levels resulting in debit balances of more than $80 million.

- **Strategic-Financial – revenue preservation**

(mitigates shareholder risk/cost associated with regulatory cost disallowance)

- **Strategic-Reputational – customer satisfaction and regulatory prudence**

(mitigates rate impacts, reduces scope 1 and 3 GHG emissions, improves public/regulatory transparency & accountability, supports responsible & safe system operations)

HIGH LEVEL TIMELINE AND KEY MILESTONES

- Charter: September 7, 2023
- Key Milestones:
  - Project Kick-Off – October 2023
    - *Short-Term Qualitative Investigations*
    - *Long-Term Data-Driven Investigations & Continuous Improvement Cycle*
  - Design & Implement Governance Model – 2024
  - Transition to Long-Term Sustainment Model - 2025

KEY PROJECT DEPENDENCIES / ASSUMPTIONS / RISK

The project mandate affords broad-based scope to identify, prioritize, & investigate all contributing sources of UFG & to propose & impose novel, or changes to existing, systems, processes, procedures & standards.

- That UFG-related proposals set out in 2024 Rebasing Settlement Proposal are acceptable to the OEB.

- The UFG accounting methodology and costs proposed for recovery via EGI's 2022 Deferral and Variance Account Clearance Application are acceptable to the OEB

STAKEHOLDERS / RESOURCING

Project Delivery & Departments Impacted

- Revenue & Cost of Gas
- Billing
- Distribution Optimization Engineering
- Measurement
- Operations & Maintenance Engineering
- Carbon Strategy
- Advisor, GHG Strategy & Reporting
- Measurement Integrity
- Capacity Planning
- Gas Supply
- Engineer Specialist, Quality Management
- Underground Storage
- Regulatory Applications

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Unabsorbed Demand Costs Deferral Account - Union Gas Exhibit E, Tab 1, p. 1

Preamble:

To meet customer demands across the Union rate zones and to meet the planned storage inventory levels at October 31, approved rates for the Union rate zones in 2022 included planned unutilized pipeline capacity of 11.3 PJ in Union North West, 3.1 PJ in Union North East and 0 PJ in Union South. The actual unutilized capacity in 2022 was 16.7 PJ, of which 1.93 PJ was in Union South. There is a debit balance of $0.810 million applicable to sales service customers related to the cost of the unutilized capacity in Union South

Question(s):

a) Please confirm that the planned unutilized capacity in Union South is set at 0 PJ as any excess pipeline capacity is used to fill storage at Dawn in a typical year.

b) Please explain why the 1.93 PJ of unutilized pipeline capacity in 2022 was not used to fill storage levels.
   i. Please explain why the proportion of total unutilized pipeline capacity substantially decreased in Union South compared to the 2021 level.

c) Please outline what measures Enbridge Gas implemented in order to reduce the total actual unutilized capacity in 2022.

Response:

a) Confirmed. For the Union South rate zone, Enbridge Gas plans for upstream pipeline capacity to flow at 100% utilization each day of the year. During times when usage is less than upstream supply, the excess supply is injected into storage at Dawn. When demands are greater than upstream supply, gas is withdrawn from storage and transported to Union South in-franchise customers. Consequently, there is no planned unutilized capacity in Union South.

b - c)

Enbridge Gas identified an error in Table 1 of Exhibit E, Tab 1. In line 1, the figures for capacity released in line 1 for the Union North East and Union South rate zones were inverted. A corrected version of Table 1 is set out below and an updated version of Exhibit E, Tab 1 has been filed with the OEB. The actual Union South capacity released in 2022 was 8.81 PJ. Enbridge Gas manages the Union rate zone transportation portfolio on an integrated basis, and the decisions about which planned supply purchase to reduce is determined based on achieving the greatest avoided cost while meeting both customer demands in the summer and storage injection requirements. As a result, Enbridge Gas fills storage using the most cost-effective supply paths, which may vary from year to year based on natural gas market price fluctuations.

Table 1

Capacity Released & Related Costs Incurred

Line No.	Particulars	Union North East	Union North West	Union South	Total Franchise Area
1	Capacity Released (TJ)	1,931	5,972	8,813	16,716
2	UDC Costs Incurred ($000's)	715	3,853	2,569	7,136
3	Released UDC Capacity ($000's)	0	(3,628)	(44)	(3,672)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Short Term Storage and Other Balancing Services Deferral Account - Union Gas Exhibit E, Tab 1, pp. 7-9 of 69, and, Exhibit E, Tab 1, Table 3, p. 8 of 69

Preamble:

The Short-term Storage and Other Balancing Services Deferral Account includes revenues from C1 Off-Peak Storage, Gas Loans, Supplemental Balancing Services and C1 Short-Term Firm Peak Storage. The net revenues from services provided was $0.117 million, of which the ratepayer share is $0.105. The balance in this deferral account is a debit from ratepayers of $4.446 million, plus interest of $0.216 million for a total debit from ratepayers of $4.662 million.

Question(s):

a) Please confirm that the correct figure in Line 2, Actual 2022, in the above-referenced table is 105, and not 12 (ratepayer 90% share of the actual 2022 Short-Term Storage and Other Balancing Services net revenue of $0.117 million).

b) The Short-term Storage and Other Balancing Services revenue for 2021 was $2.610 million, which increased to $3.297 million in 2022. However, O&M costs for 2022 ($1.172 million) represent a marginal increase over the $1.004 million in 2021 O&M.

   i. Please explain why O&M costs for 2022 increased marginally as compared to 2021 while revenue increased significantly.

c) Unaccounted for Gas (UFG) costs for 2022 were $1.521 million as compared to $266,000 in 2021.

   i. Please explain why UFG costs increased nearly six-fold for 2022 as compared to 2021.

d) Please explain why total costs for 2022 ($3.18 million) more than doubled from 2021 ($1.528 million).

<u>Response:</u>

a) Confirmed. The correct figure in line 2 of Exhibit E, Tab 1, Table 3, page 8 of 69 is 105.

b) The O&M costs attributed to the Short-term Storage and Other Balancing Services Deferral account are based on the proportion of excess utility space available in 2022 relative to the 2013 OEB-approved excess utility space multiplied by the 2013 OEB approved cross charge. The 2022 O&M cost is higher than 2021 due to the increase in excess utility space vs 2021. There is no direct correlation between the revenue amount and the O&M costs for a particular year.

c) The UFG costs increased in 2022 as compared to 2021 primarily due to the increase in UFG expense as discussed in Exhibit E, Tab 1, pages 28 to 48. The increase was also partially due to an increase in the short-term storage activity proportion of total throughput activity used to allocate UFG, which includes in-franchise and exfranchise throughput, and storage injection/withdrawal activity.

d) Total costs attributed to the Short-term Storage and Other Balancing Services Deferral account are composed of UFG, Compressor fuel and O&M. UFG and O&M variances are described in part b) and c) above, of which UFG accounts for the majority of the 2022 increase. Compressor fuel is based on the short-term storage ratio of total storage activity and associated compressor fuel cost. Compressor fuel cost in 2022 were higher due primarily to higher fuel commodity pricing.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Integrated Resource Planning Operating Costs Deferral Account
Exhibit C, Tab 1, p. 16

Preamble:

The 2022 Integrated Resource Planning (IRP) Operating Cost Deferral Account has a debit balance of $2.285 million (including interest).

Enbridge Gas is proposing to recover $1.773 million in the IRP Operating Costs Deferral Account related to staff salaries and expenses. In 2022, there was 13.5 Full Time Equivalent (FTE) additions and employee expenses associated with IRP. Enbridge Gas stated that this is in addition to the 3 FTE IRP roles that are already captured in Operating and Maintenance (O&M).

Question(s):

a) Please confirm how many FTE IRP roles Enbridge Gas had in 2021 and the balance recovered in the 2021 IRP Operating Cost Deferral Account associated with those FTE IRP roles.
    i. Does Enbridge Gas expect to continue increasing the number of FTE IRP roles in future years? Please provide further details.

b) Please confirm if Enbridge Gas had a total of 16.5 FTE IRP roles in 2022 (3 captured in O&M).

c) Please explain why the 3 FTE IRP roles referenced above were captured in O&M and not in the IRP Operating Cost Deferral Account
    i. Please provide the costs associated with these 3 FTE IRP roles captured in O&M.

Response:

a) Enbridge Gas included 1.5 FTE IRP roles in the 2021 IRP Operating Cost Deferral Account, however, the costs included were minimal as the 1.5 FTE's were included in the 2021 IRP Operating Cost Deferral Account starting in late 2021, after the IRP Decision was released in July 2021.[1]

   i) To ensure that IRP is considered and supported within Enbridge Gas, additional IRP resources will be hired directly into the respective teams if incremental workload is identified. This will ensure that a strong, ongoing, focus remains on the coordination and implementation of integrated resource planning across the Company.

b) Confirmed.

c) The 3 FTE IRP roles that are included within O&M, are IRP roles that existed within Enbridge Gas's O&M budget prior to the IRP Decision being issued.

   i) The O&M costs for the 3 IRP FTE roles in 2022 were approximately $338,000.

[1] EB-2020-0091, OEB Decision and Order, dated July 22, 2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Integrated Resource Planning Operating Costs Deferral Account Exhibit C, Tab 1, p. 21

Preamble:

The proposed IRPAs are not able to address the class location and depth of cover concerns; therefore, Enbridge Gas will continue to monitor these assets to ensure the risk remains tolerable. As the project is reassessed to identify if and when future system reinforcement may be required, remedies to the class location and depth of cover concerns will be considered.

Question(s):

a) Please provide additional details on what remedies Enbridge Gas will consider if system reinforcement is required.

Response:

a) There are a few options available to mitigate depth of cover issues and class location issues. These are subject to a variety of factors, including the practicality and constructability of the options. Additionally, the only options that address the need for an increased pipe size to meet demand would be a replacement or relocation.

   The two primary mitigations for depth of cover are lowering of the pipeline in place or replacement of the pipelines (either in place or a new location). Lowering of the pipeline is an option that is frequently used when addressing depth of cover challenges, however, this option would not provide an increase in capacity and would result in a similar amount of construction activity. Additionally, depth of cover issues exist in areas where rock exists, further lowering the feasibility of the option. A replacement would allow for the pipe to be brought to current standards and allow for increased capacity.

   For class location issues, the options that are generally available are either replacement using pipeline materials that result in a higher design pressure in the same place, lowering the operating pressure of the pipeline, or relocating to an area of lower building or population density. Replacement along the same routing with pipeline materials used for a higher design pressure, can result in removing the class location issues, but may not be the most optimal routing over time or as the community grows. Lowering the operating pressure of a pipeline can result in long-term gas supply challenges and would be counterproductive to an expansion project. Relocation from the area of concern provides the flexibility to remove the class location issue and provide optimal routing while minimizing the encroachment on the pipeline.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Normalized Average Consumption Deferral Account - Union Gas Exhibit E, Tab 1, pp. 12-16 of 69

Preamble:

The deferral account balance is calculated by multiplying the variance between the weather normalized target NAC and the weather normalized actual NAC by the 2013 OEB-approved number of customers and the 2022 OEB-approved delivery and storage rates for each general service rate class. For rate classes M1, M2, 01 and 10, two variances have been calculated for each rate class to determine delivery and storage revenues: one is the variance between target and actual NAC for base rates and the other similar variance for Y-factor rates. The Variance (Target minus Actual NAC) differs under both calculations (Base Rates and Y Factor Rates).

Question(s):

a) Please provide a detailed calculation that shows how the variance calculations (Target minus Actual NAC) for base rates and Y-factor rates are used to determine the NAC deferral account balance

b) Please identify the specific components to which the base and Y-factor rates adjustments apply.

Response:

a) Please refer to Exhibit E, Tab 1, Schedule 5 which provides the detailed calculation that shows how the variance calculations for base rates and Y-factor rates determine the NAC deferral account balance.

b) Please refer to Exhibit E, Tab 1, Schedule 5 which identifies the specific components to which the base and Y-factor rate adjustments are applied. As a summary, the specific components are indicated in Table 1.

Table 1
Base Rate & Y-factor Rate Components

Line No.	Rate Type (a)	Components Applied (b)
1	Base Rates	Target (forecasted) NAC Actual NAC Total Delivery Base Rate Total Storage Base Rate 2013 OEB-approved number of customers
2	Y-factor Rates	Target (forecasted) NAC Actual NAC Total Delivery Y-factor Rate Total Storage Y-factor Rate 2013 OEB-approved number of customers

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Normalized Average Consumption Deferral Account – Union Gas Exhibit E, Tab 1, pp. 12-14 of 69

Preamble:

For 2022, the balance in the NAC deferral account is a debit to ratepayers of $8.770 million plus interest of $0.565 million for a total debit to ratepayers of $9.334 million. The 2019 actual NAC, weather normalized using the 2022 weather normal was used to determine the 2022 target NAC for each rate class to calculate base rates. The 2022 actual NAC for each rate class is weather normalized using the 2022 weather normal, which is produced using the OEB-approved weather methodology. For 2022, the target NAC was greater than the actual NAC across all rate classes (Rate 01, Rate 10, Rate M1, Rate M2).

Question(s):

a) Please provide a rate class graphical representation of normalized average use per customer for the years 2019 to 2021(show forecast and actual).

Response:

As stated in Exhibit E, Tab 1, page 12, the 2020 actual NAC, weather normalized using the 2022 weather normal, was used to determine the 2022 target NAC for each rate class to calculate base rates.

The charts below provide a graphical representation of normalized average use per customer and illustrates the actual NAC and target (forecasted) NAC for Rate 01, Rate 10, Rate M1, and Rate M2 for 2019 to 2022. Please note that the actual and target (forecasted) NAC are weather normalized at each year's respective OEB-approved weather normal.

Figure 1
Rate M1 Normalized Average Consumption: Actual vs Target (Forecast)

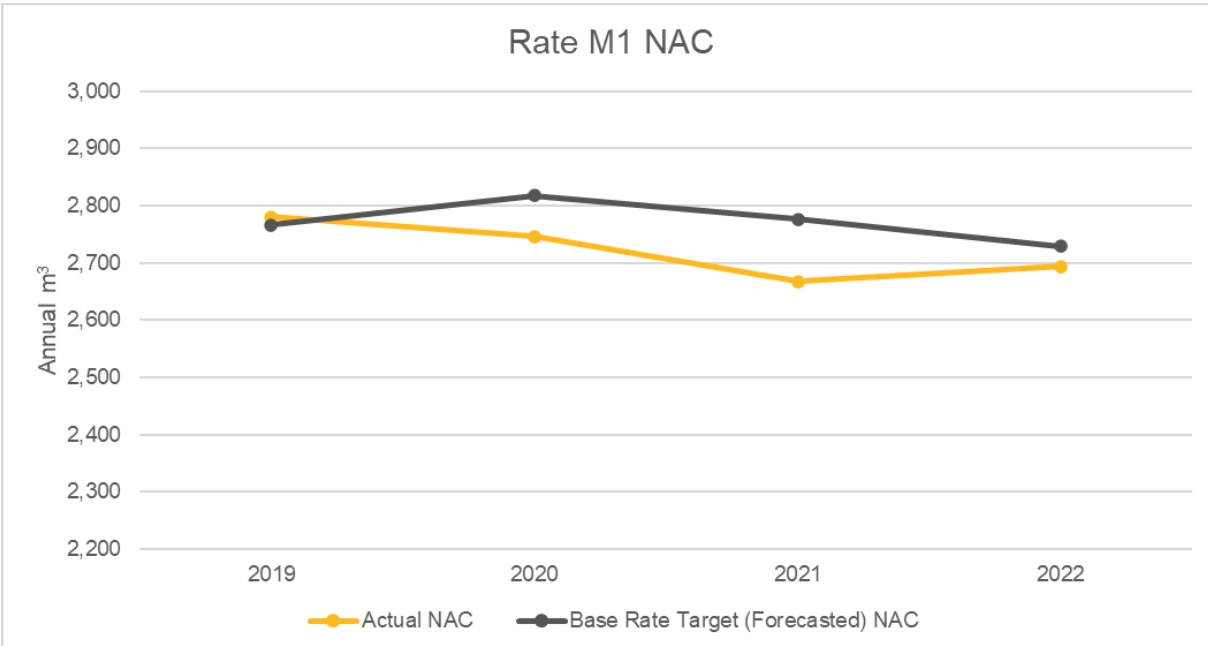


Figure 2
Rate M2 Normalized Average Consumption: Actual vs Target (Forecast)

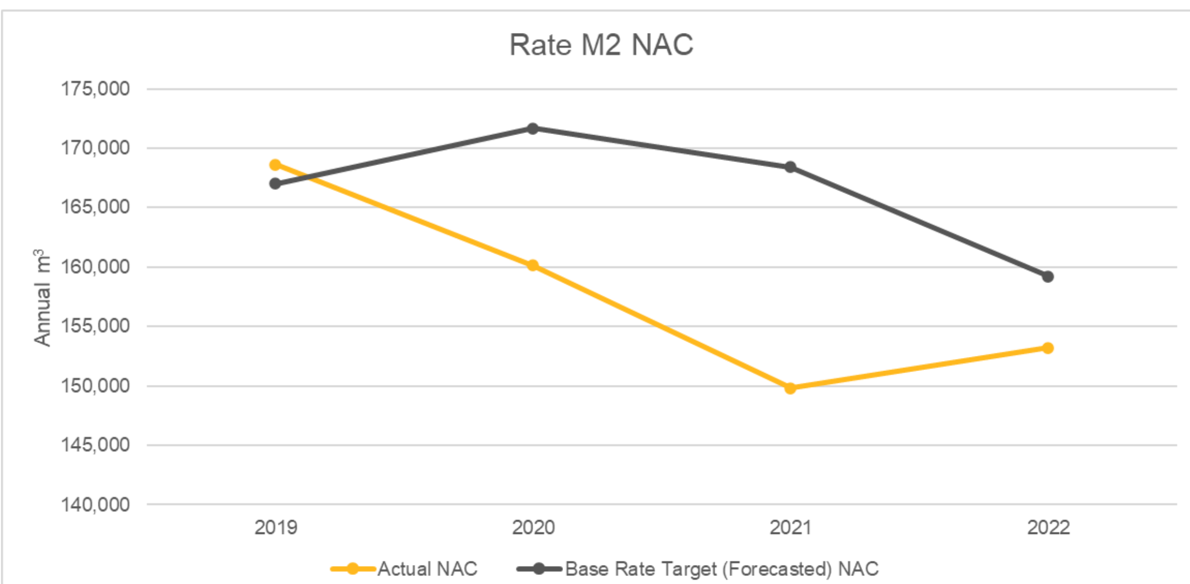


Figure 3
Rate 01 Normalized Average Consumption: Actual vs Target (Forecast)

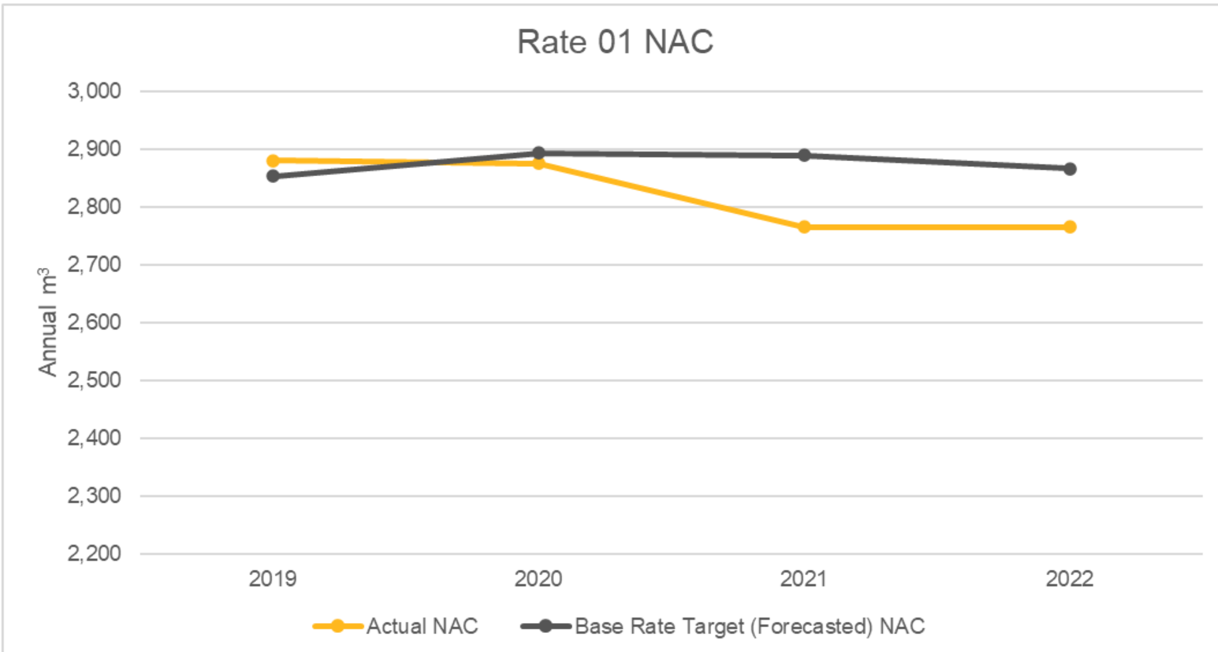
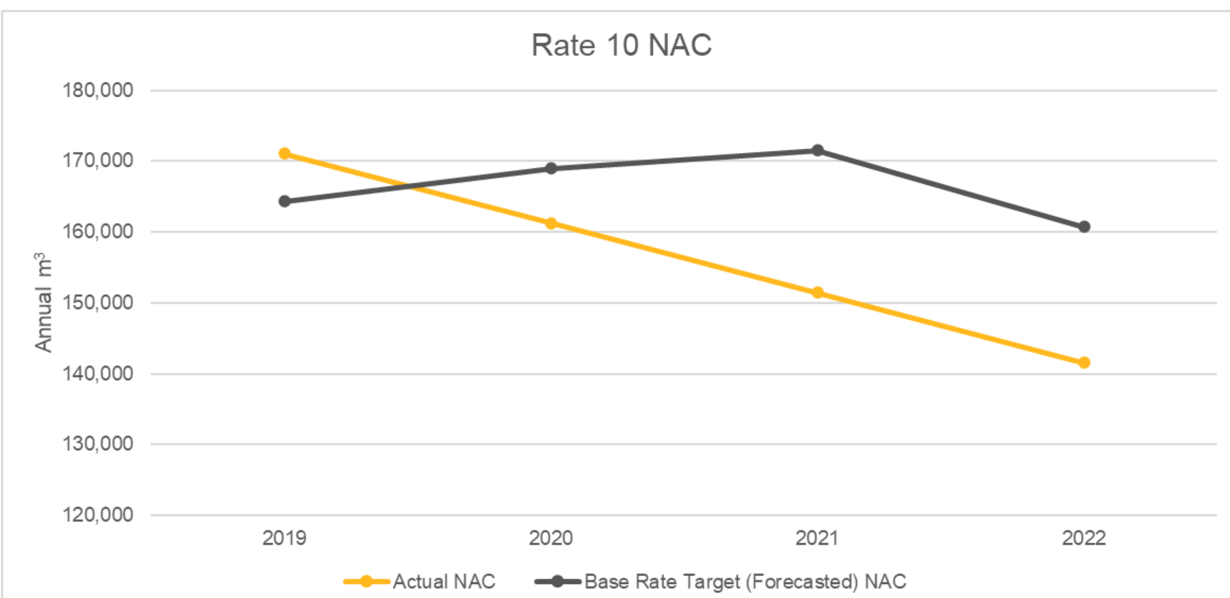


Figure 4
Rate 10 Normalized Average Consumption: Actual vs Target (Forecast)



ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Page 1,

Question(s):

Please provide a reconciliation with variance explanations between EB-2023-0092 Exhibit B, Tab 1, Schedule 1, Page 1, Filed 2023-06-14, and EB-2022-0200 Exhibit 5, Tab 2, Schedule 1, Attachment 4, Page 2, Updated 2023-03-06.

Response:

Enbridge Gas first notes that the results of the (deficiency)/sufficiency contained in EB-2023-0092 Exhibit B, Tab 1, Schedule 1, page 1 are based on an approved Return on Equity (ROE) of 10.16% representing 2022 OEB Approved ROE of 8.66% plus 150bps. Whereas the results in EB-2022-0200 Exhibit 5, Tab 2, Schedule 1, Attachment 4, page 2 are purely based off of the 2022 OEB Approved ROE of 8.66% not including the 150bps allowed before earnings sharing.

Provided in Table 1 below are the summary results of 2022 Estimate as per EB-2022-0200 Exhibit 5, Tab 2, Schedule 1, Attachment 4, page 2 and 2022 Actuals based off of an OEB Approved 8.66% ROE for comparative purposes:

Table 1

Summary of 2022 Estimate vs Actual Results

Line No.	Particulars ($ millions)	2022 Actual	2022 Estimate	Variance
1	Rate Base	15,381.4	15,101.3	280.1
2	Utility Income after tax	930.1	889.8	40.3
3	Net (deficiency)sufficiency	47.3	20.0	27.3
4	Allowed ROE	8.66%	8.66%	-
5	Achieved ROE	9.515%	9.028%	0.487%

The variances noted above are explained below:

1. Rate base was $280.1 million higher in 2022 actuals compared to the 2022 estimate resulting in a $13.0 million higher revenue requirement. As described in the Capital Update filed in EB-2022-0200, Exhibit 2, Tab 5, Schedule 4, page 27, updated June 16, 2023:

   > This increase was primarily attributable to a $259.6 million increase in working capital primarily related to a higher average Gas in Storage balance resulting from a higher average reference price during 2022. A further increase of $20.3 million is attributable to lower actual depreciation in 2022 partially offset by lower in-service additions.

2. Utility income after tax was $40.3 million higher in 2022 actuals compared to the 2022 estimate. This variance was primarily related to a higher gas sales and distribution revenue net of gas costs of approximately $27.2 million and lower depreciation expense of $52.3 million, partially offset by a higher utility O&M expense of $38.4 million.

   The lower depreciation of $52.3 million is related primarily to overall lower in-service additions in actuals, in particular TIS projects, as well as depreciation impacts related to actual retirements recognized during the year.

   The higher O&M of $38.4 million is primarily related to higher central functions costs allocated in 2022 actuals, due to higher STIP, LTIP and other employee benefit expenses, partially offset by savings in pension expense.

3. The higher utility income after tax is partially offset by the higher required return on rate base resulting in a net $27.3 million higher net sufficiency realized in 2022 actuals compared to the 2022 estimate resulting in a 0.487% higher achieved ROE.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 6, Page 1, Col.1, Line 6

Question(s):

a) What is Other Income of $79.2 million?

b) Please break down $79.2 million Other Income into Revenues and Expenses.

Response:

a) Other Income of $79.2 million as reported on Enbridge Gas's December 31, 2022 Consolidated Financial Statements[1] is represented by:

    i. Other pension related net revenues that are not reported in O&M for financial reporting purposes under US GAAP, however reclassified to O&M for Utility reporting (see response to b) below for details).
    ii. Amortization of Union's pre-2017 net actuarial (gains)/losses, as above reported in O&M for financial reporting purposes under US GAAP, however reclassified to O&M for Utility reporting.
    iii. Gain on sale of the land portion of the Thorold property disposition.
    iv. Net foreign exchange losses realized during the year.
    v. Revenue indemnification received from Enbridge Inc. related to a non-utility Corporate tax planning Part VI.1 tax that ensures EGI is tax neutral.
    vi. Interest income from affiliates.
    vii. Various other offsetting income amounts not individually material.

[1] Exhibit I.FRPO.9 Attachment 1, p. 6.

b) Other Income of $79.2 million is broken down by the following:

Table 1

Other Income

Line No.	Particulars	$ millions
1	Interest cost	(64.3)
2	Expected return on plan assets	151.4
3	Amortization of net actuarial (gain)/loss	(8.0)
4	OPEB cost	(3.4)
5	Subtotal – Other pension related expense[2]	75.7
6	Amortization of pre-2017 Union actuarial (gain)/loss[3]	(9.1)
7	Subtotal – Pension related other net revenue	66.6
8	Gain on disposition of assets	3.6
9	Foreign exchange losses	(6.7)
10	Revenue indemnification received from Enbridge Inc. related to tax planning Part VI.1 tax	11.5
11	Interest income from affiliates	3.4
12	Other income	0.8
13	Total – Other Income	79.2

[2] Exhibit I.FRPO.9 Attachment 1, p. 36.
[3] EB-2022-0200, Exhibit JT3.37, Attachment 1, col (e), line 26.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, Page 3, Paragraph 5

Preamble:

“CSS costs were $67.1 million higher than the prior year primarily due to: a higher share price and stronger Enbridge Inc. performance that has resulted in higher LTIP and STIP, higher legislative benefit costs resulting from a year over year change in maximum contribution levels, higher TIS costs related to additional mandated cybersecurity costs and incremental sustainment costs related to the addition of 1.6 million customers to the CIS system in 2021. These variances were partially offset by higher overhead capitalization of CSS costs, lower pension costs and a decrease in insurance premium costs.”

Question(s):

a) Please break down the $67.1 million variance into the components mentioned in the quoted paragraph.

b) Why should ratepayers pay for higher 2022 LTIP and STIP for Enbridge Gas Inc. management when Enbridge Gas Inc. 2022 earnings are inadequate for earnings sharing?

Response:

a) Please see Table 1.

Table 1
Enbridge Gas Inc.
Central Functions O&M Variance

Line No.	Particulars ($ millions)	2022 vs 2021 Variance
1	TIS	25
2	STIP	6
3	LTIP	39
4	Legislative Benefits	20
5	Pension and OPEB	(18)
6	Insurance	(6)
7	Capitalization[1]	(25)
8	Other Central Functions[2]	26
9	Total	67

b) As described in EB-2022-0200, Exhibit 4, Tab 4, Schedule 3, paragraphs 29 and 30, STIP and LTIP are a part of Enbridge Gas's competitive and comprehensive compensation program to support workforce recruitment and retention objectives. They are costs that are properly reflected in determining earnings for ESM purposes, and they have been included in ESM calculations for each year of the deferred rebasing term (and for EGD before that).

STIP is an annual cash-based incentive plan that rewards enterprise, business unit and individual/team performance. Each year, goals are set across the enterprise and within each business unit to focus on strategic priorities and align with external stakeholder interests (e.g., customers, investors, regulators) to ensure safe, efficient, and effective processes and a skilled, knowledgeable workforce to carry out those strategies. While financial performance is a key component of the STIP performance, safety and reliability is another critical performance measure.

[1] Higher capitalization resulting in lower O&M.
[2] Other CFCAM areas with variances individually immaterial, including Finance, Legal, etc.

LTIP as the name implies is focused on rewarding the achievement of Enbridge Gas's long-term goals or strategic objectives for employees at the manager level and higher. These goals, such as growing the business, take several years to achieve. LTIP consists of stock option and share unit plans. LTIP provides participants the opportunity to benefit from the value that has been created as strategic objectives are achieved. It can take several years to realize this benefit, and the value is uncertain (i.e., pay at risk). LTIP aids in the attraction, motivation and retention of leadership talent who possess the competency, knowledge, experience and skills to operate the utility safely and is consistent with the expectations of all stakeholders including customers.

Consistent with prior year actual results and forecasts used for rate setting purposes, STIP and LTIP are two of the components of Enbridge Gas's overall competitive and comprehensive compensation program which in its entirety supports workforce recruitment and retention. The value of STIP and LTIP amounts are dependent on a number of financial and non-financial (i.e. safety) variables/metrics which measure Company success/performance, not solely utility earnings and any resultant earnings sharing. The Company notes that utility earnings sharing is based on a 150 bp stretch for the Company and reflects factors and or pressures beyond management control (i.e. weather or inflation) while STIP metrics are based on what is in management's control.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, Page 5, Paragraph 10

Preamble:

"Compensations and Benefits decreased by $5.5 million over the prior year primarily due to: lower pension cost and lower STIP (which is based on business unit performance/scorecards) resulting from a decrease in Enbridge Gas performance compared to 2021. These decreases were partially offset by increases in merit, higher FTEs, higher LTIP related to a higher share price and higher legislative benefit costs resulting from a year over year change in maximum contribution levels".

Question(s):

Please reconcile the statement in the quoted paragraph regarding lower STIP with the statement in paragraph 5 on Page 3 regarding higher STIP.

Response:

Corporate Shared Services (CSS) costs are allocated amongst Enbridge Gas's affiliates based on the internally developed CFCAM model. Please see response at Exhibit I.STAFF.1, part c) for more details. In paragraph 5, the explanation is referring to CSS component of STIP which is allocated through CFCAM. Compared to 2021, CSS had stronger results and higher STIP whereas in paragraph 10, the compensation and benefits are referring to the business unit component (non-CSS) of compensation and benefits which had lower performance and lower STIP compared to 2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit D, Tab 1, Page 3, Paragraph 6

Preamble:

“Enbridge Gas required this annual replacement of third-party storage in order to reliably and cost effectively meet demand on peak winter days as well as retain late season deliverability. The RFP responses were received by Enbridge Gas on December 2, 2021. The RFP manager made the recommendation and Enbridge Gas transacted based on the recommendation. Bids received and those that were selected are outlined in Confidential Exhibit D, Tab 1, Schedule 6.”

Question(s):

Were any of the selected bids from affiliates of Enbridge Gas Inc. or from any entities that are wholly or partially owned by Enbridge Inc.?

Response:

Yes. Please see the response to Exhibit I.FRPO.4.1, filed in confidence with the OEB.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit D, Tab 1, Page 11, Paragraph 11

Preamble:

"Figure 2 shows that the EGD and Union Rate Zones' UFG levels and annual fluctuations are generally consistent with other gas utilities. It also demonstrates that while Enbridge Gas has experienced recent increases in UFG levels in the EGD Rate Zone in 2022 and in the Union Rate Zones in 2021/2022, UFG levels are now trending lower for 2023 YTD."

Question(s):

a) Has Enbridge identified the main reason for the large increase in UFG in 2022? If the answer is yes, please provide the main reason for the increase. If the answer is no, please explain why not, and provide the date when the main reason will be identified.

b) What incentive does Enbridge have to minimize UFG?

c) What is the latest information on UFG levels for 2023?

Response:

a) Please see response at Exhibit I.STAFF.6 parts a) and b).

b) Enbridge Gas is incented to minimize UFG as it impacts the cost to serve customers. Further, as discussed in Exhibit E, Tab 1, paragraphs 2 and 7, the OEB established a symmetrical deadband for the Union Rate Zones (UFGVDA) of $5 million. As a result of this deadband, Enbridge Gas is unable to seek recovery of UFG-related costs above the OEB-approved UFG % (0.219%), until the $5 million is exceeded. As noted in Table 3 of Exhibit E, Tab 1, as a result of the deadband, Enbridge Gas has been prevented from recovering a total of $27.8 million of UFG-related costs since 2014.

c) 2023 regulated aggregated UFG volumes as of September 30, 2023 are:

- EGD rate zone: 43,130 10^3m^3
- Union rate zones: 48,225 10^3m^3 [1]

[1] Includes utility and non-utility volumes, consistent with the presentation of volumes in Exhibit E, Tab 1, Table 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit D, Tab 1, Page 18, Paragraph 28

Preamble:

"On a monthly basis, the calculation of UAF volumes is recorded based on an annual heat value for natural gas delivered to customers. In the following month, when the actual heat values are available, the difference between the actual and annual heat value is recorded in the UAFVA."

Question(s):

a) Does Enbridge have equipment at each receipt point that measures heat value? If the answer is yes, please file a table of heat values by receipt point by month for 2022. If the answer is no, please explain why not.

b) Do heat values vary by receipt point and by date of receipt? Please explain your answer.

c) How is the annual heat value determined? For example, is it just a simple annual average or is it prorated by receipt point?

d) Has Enbridge attempted to correlate the differences in heat values with UFG?

Response:

a) Please refer to Table 1 for the aggregated receipt point values used to calculate UAF for the EGD rate zone.

Table 1
Monthly Heat Values for ECDA and EEDA for 2022

Line No.	Particulars	ECDA HV	EEDA HV
		(a)	(b)
1	January 2022	39.18	39.02
2	February 2022	39.14	39.03
3	March 2022	39.13	38.88
4	April 2022	38.95	38.84
5	May 2022	38.62	38.93
6	June 2022	38.54	38.68
7	July 2022	38.58	38.63
8	August 2022	38.77	38.74
9	September 2022	38.73	38.90
10	October 2022	38.77	38.67
11	November 2022	38.97	38.78
12	December 2022	39.09	39.02

b) Heat values are determined by measured gas quality and therefore will differ between receipt locations and dates.

c) Annual heat value (AHV) is determined by taking the total annual sendout quantity in units of energy (GJ) divided by the total annual sendout quantity in units of volumes (m3). Total annual sendout quantity is the difference between the total gas received at all receipt points and the gas delivered from all locations.

AHV = Annual Quantity (GJ) / Annual Quantity ($10^3 m^3$)

where Annual Quantity = ∑ Annual Receipts - ∑ Annual Deliveries

d) No, Enbridge Gas has not yet attempted an in-depth analysis seeking to definitively determine the existence and specific nature of any correlation between location-specific heat values (i.e., for each receipt and delivery point on the Enbridge Gas system) and UFG. Such an analysis is expected to be extremely detailed and time intensive. However, consistent with the response set out at Exhibit I.STAFF.6, analyses of this nature may fall within the scope of work contemplated for the UFG Team and supporting business areas in the future.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1, Page 18, Section 3.4, “Identify and Standardize Best Practices at EGI”

Preamble:

“A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term.”

Question(s):

a) Please confirm that UFG has increased since the move from monthly meter reading to bi-monthly meter reading.

b) The last sentence mentions “increased volatility in the short-term”. Could the short-term last for more than a year?

c) Please confirm that LEGD estimated the consumption in the month that the meter is not read on the consumption at the same premise in the same month of the previous year adjusted for degree days. Please explain your answer.

Response:

a) Not confirmed. Historical UFG volumes for the Union Gas Rate Zones can be found in Exhibit E, Tab 1, page 30, Table 2. A subset of historical volumes for the Union Rate Zones is provided in Table 1, starting in 2019 to align with the timing of the change from monthly meter reading to bi-monthly meter reading.

Table 1:
Historical UFG Volumes for Union Rate Zones for 2019-2023 YTD

Line No.	Calendar Year	UFG Volumes (10^3m^3)
1	2019	137,652
2	2020	74,120
3	2021	252,282
4	2022	250,692
5	2023 YTD	45,225[1]

As detailed in Table 1, UFG volumes decreased in 2020 and increased in 2021 and 2022 in comparison to 2019 levels. While UFG volumes were higher in two out of three years since 2019, the correlation does not necessarily represent causation. The 2019 Report on Unaccounted for Gas noted that fluctuations in UFG are a result of many factors including weather, estimation variation, measurement variation and billing and accounting adjustments. It further noted that sources of UFG include physical losses, metering variations, non-registering meters, theft, line pack and billing and accounting adjustments.[2] While the change from monthly to bi-monthly meter reading does not contribute to incremental UFG, it could contribute to increased volatility in the short-term.

b) Exhibit D, Tab 1, Schedule 1, page 18, Section 3.4 refers to the 2019 Report on Unaccounted for Gas,[3] where it is noted that usage estimation variances "….generally reverse or correct themselves within a one-year period". However, when estimation variances cross over accounting reporting periods, it may result in volatility in multiple years, when results are reported on an annual basis. In the case of estimation variances associated with estimated meter reads, a true-up will occur when an actual meter read is next recorded. With a bi-monthly meter reading schedule, this means that generally a true-up will occur within two months of consumption.

c) Confirmed. Exhibit D, Tab 1, Section 4.2 provides a description of the process for the calculation of billed consumption based on estimated meter reads as follows:

> Estimated meter reads are calculated at the individual customer level based on consumption history for their respective premise(s). When insufficient usage history exists to derive an accurate estimated meter read, the billing system uses a combination of degree day data and standard factors for the customer's property type to derive an estimate.[4]

[1] 2023 regulated aggregated UFG volumes as of September 30, 2023.
[2] EB-2019-0194, Report on Unaccounted for Gas, pp. 4-5.
[3] EB-2019-0194, Report on Unaccounted for Gas, p. 44.
[4] EB-2023-0092, Exhibit D, Tab 1, p. 14.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit E, Tab 1, pages 39 and 40

Question(s):

a) How does Enbridge determine the sendout total? Is sendout the sum of units of energy received at all receipt points and converted into units of volume using the heat value at each receipt point as the conversion factor?

b) Please confirm heat value would have an impact on UFG if sendout volumes are derived using heat values and consumption volumes are not.

Response:

a) Sendout is the net amount of gas delivered into the franchise area, which is the difference between the amount of gas received at all receipt points (e.g. pipeline interconnects and storage pools) and the gas delivered to all delivery points (e.g. pipeline interconnects and storage pools). Sendout is measured and reported in both units of volume (m^3) and units of energy (GJ), the latter of which is based on the actual heat value established at each location.

b) Confirmed. However, using different heat values for sendout and consumption volumes would not be appropriate. As described in Exhibit E, Tab 1, page 42, Enbridge Gas trues up consumption volumes to actual heat values on a monthly basis to avoid this.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2

Preamble:

We would like to understand the components of gas cost that are allocated to non-utility storage in Column 2.

Question(s):

Please provide a description of the components of gas cost that are allocated to non-utility storage and the allocation methodologies.

a) Please provide a specific reference to the Board approval of those allocation methodologies.

b) For each year, 2020 to 2022, please provide the allocations to the respective components identified.

Response:

The legacy EGD and Union allocation methodologies have been described in detail and provided as part of EB-2022-0200, Exhibit 1, Tab 13, Schedule 2, Attachment 1. Summaries from evidence are provided below:

- Third Party Market Based Storage Costs incurred by the Unregulated business are procured specifically driven by services, activities and contracts which are exclusively unregulated. There is therefore no allocation process required.

- Allocation of Unaccounted for Gas (UFG) – Union Rate Zones: Total actual unaccounted for gas incurred is allocated to the unregulated storage operations on an annual basis using a volumetric allocator based on actual gross unregulated storage activity as a percentage of total actual gross storage and transportation activity. Gross activity is the sum of absolute volumes as it relates to both injections and withdrawals.

- Allocation of Lost and Unaccounted for Gas (LUF) – EGD Rate Zone: With regard to gas losses from Storage Operations, currently, 14.3% of the total LUF provision for storage (0.12 bcf) is designated as being related to the unregulated storage operations, based on volumetric drivers for storage capacity measured in 2015, and the capacity-based allocator used to determine the LUF related to the unregulated storage operations has not been updated with current capacity. The 0.12 bcf of LUF associated with the unregulated storage business is applied to the Quarterly Rate Adjustment Mechanism (QRAM) reference price of gas to determine the cost.

- Allocation of Fuels – Union Rate Zones: Total actual fuel consumed is allocated to the unregulated storage operations daily using a volumetric allocator based on net daily unregulated storage activity as a percentage of net daily total activity for storage and transportation. Net activity is composed of injections less withdrawals.

- Allocation of Fuels – EGD Rate Zone: Total actual storage fuel consumed is allocated to the unregulated storage operations on a monthly basis. The unregulated portion is calculated by first determining a compressor fuel consumption percentage (total fuel consumed for storage as a percentage of total monthly storage activity, represented as the difference between the opening and closing balance), and applying that fuel consumption percentage to the monthly unregulated activity (represented as the difference between the opening and closing unregulated balance).

- Allocation of Facility Carbon Costs to Unregulated: The allocation of facility related carbon costs occurs in a manner similar to the above for allocating compressor fuel costs between regulated and unregulated. [N]on-utility fuel volumes are determined based on actual storage fuel usage apportioned based on the percentage of regulated versus non-regulated activity. The non-utility fuel volumes are separated from Enbridge Gas's regulated utility fuel volumes for the purposes of determining regulated costs.

a) OEB approval of the above methodologies prior to harmonization are noted below:

   i. UFG and Fuels – Union Rate Zones: Approved as part of decision on Cost Allocation studies[1][2][3] in EB-2011-0038[4]

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[1] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008).
[2] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review.
[3] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review.
[4] EB-2011-0038, Decision and Order, dated January 20, 2012.

ii. LUF and Fuels – EGD Rate Zone: Approved as part of decision on Cost Allocation studies[5] in EB-2015-0114[6]

iii. Facility Carbon Costs – The allocation methodology was first described in EGI's 2021 Federal Carbon Pricing Program Application.[7]

b) Components of unregulated gas costs are provided below:

Table 1

Summary of Unregulated Gas Costs

Line No.	Unregulated Gas Costs	2020	2021	2022
1	Third Party Market Based Storage costs	17.9	16.8	28.1
2	Unaccounted for Gas	1.3	2.6	4.8
3	Net Compressor Fuel[8] costs	(0.6)	0.6	(1.6)
4	Facility Federal Carbon and other costs	0.1	0.2	0.4
5	Total	18.7	20.2	31.7

[5] EB-2015-0114, Exhibit A1, Tab 5, Schedule 1, p. 2 of 6.
[6] EB-2015-0114, Decision and Interim Rate Order, dated December 10, 2015.
[7] EB-2020-0212, Exhibit I.EP.9 and Exhibit I.EP.12.
[8] Compressor fuel net of customer supplied fuel.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 4, Page 3

Preamble:

In the EGD Rate Zone Underground Storage Plant table, column 2 provides additions in the total of $49.7M.

Question(s):

For each specific project over a million dollars that contribute to the additions, please provide:

a) A description of the project
b) A Board approval reference, if any
c) A specific description of the functionality created, improved or replaced as a result of the capital invested including:
    i) Any revision to storage space available
        1) If additional storage space, please provide how much space was allocated to utility operations or non-utility operations.
    ii) Any revision to deliverability available
        1) If additional deliverability, please provide how much space was allocated to utility operations or non-utility operations.

d) For each project, please define in gas being moved for non-utility storage contracts moves through the modified, upgraded or replaced facilities.
    i) The allocation of costs between utility and non-utility
    ii) the specific basis for the allocation approach
    iii) The reasoning associated with that allocation basis

e) Please describe the determination of the $6.0M in regulatory overheads including the determination and basis for allocation of regulatory overheads to the non-utility.

Response:

a) - d)

All allocations of project costs between utility and non-utility or regulated and unregulated assets are based on the unregulated storage cost allocation studies previously approved by the OEB. The split between unregulated storage assets and regulated utility assets at each individual storage pool is updated annually to reflect additions and retirements that occurred throughout the prior year, for the purposes of allocating costs associated with capital maintenance of the assets.

As previously noted in EB-2022-0086[1], due to the integrated nature of the Dawn Hub, and as the Dawn Hub has grown over time, utility and non-utility space and molecules are inherently interconnected and cannot be separated operationally.

As a result, the projects listed below will serve both utility and non-utility operations. However, the cost allocation between utility and non-utility operations depends on the nature of the assets, including whether they replace existing assets and/or create new storage capacity. This is consistent with the current storage cost allocation methodology.

The costs shown below for each project exclude indirect overheads.

SCOR:Meter Area Upgrade Phase 2 (IC 500440):

- 2022 regulated capital additions to underground storage assets - $21,545,300.
- The scope of this work includes costs to replace meter run piping and install new header cross-over and isolation valves as well as installation of an east section of new NPS 30 A, B, C headers and tie in east & west header sections
- There is no OEB approval for the project.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

SCOR:100MOD HdrValves Replace (IC 736340):

- 2022 regulated capital additions to underground storage assets - $1,030,420
- The scope of this work includes replacing all MOD valves associated with compressor units K709 & K710. Costs include design, prefabrication of piping, cut out existing valves, installing supports as required, install new piping and valves and remediating site.

[1] EB-2022-0086, Exhibit I.SEC.18, part d).

- There is no OEB approval for the project.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

<u>2021 LAD MS and PL Upgrade (IC 736064/736065):</u>

- 2022 regulated capital additions to underground storage assets - $1,300,534.
- The scope of this work includes installation costs for permanent in-line inspection (ILI) tool launcher facilities.
- There is no OEB approval for the project.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 88% regulated and 12% unregulated based on the storage cost allocation methodology.

<u>SCOR:62209-PSV-013-Incr Cap (IC 501322):</u>

- 2022 regulated capital additions to underground storage assets - $1,025,884.
- The scope of this work includes replacing the undersized, discharge Pressure Safety Valve associated with compressor unit K709 as well as adding Emergency Shutdown Valve upstream of the discharge manifold. Costs include design, fabrication and installation.
- There is no OEB approval for the project.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

<u>SCOR:62204 Dis Header OPP-Re (IC 100875):</u>

- 2022 regulated capital additions to underground storage assets - $1,046,813.
- The scope of this work includes modifying discharge header piping, increasing the size of the Pressure Safety Valve and adding a secondary isolation valve associated with compressor unit K704. Costs include design, fabrication, and installation.
- There is no OEB approval for the project.

- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

<u>NPS 16 WLK Gathering Retrofit (IC 1915/738621):</u>

- 2022 regulated capital additions to underground storage assets - $1,022,144.
- The scope of this work includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities so they can be inspected with ILI tools.
- There is no OEB approval for the project.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 65% regulated and 35% unregulated based on the storage cost allocation methodology.

<u>SCOR:60005 iBalance Upgrade (IC 3449):</u>

- 2022 regulated capital additions to underground storage assets - $913,798.
- The scope of this work includes the purchase and installation of a single iBalance system on a compressor engine that currently has no autobalancing capability. Costs include installation of new automated gas valves on the engine as well as new monitoring equipment on the engine and compressor.
- There is no OEB approval for the project.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

e) The $6 million in regulatory overheads relates to the Union rate zone, please see Exhibit B, Tab 1, Schedule 4, page 4, line 56. The indirect overheads for the EGD rate zone are included in the plant accounts and amount to $13.6 million for 2022.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 4, Page 4

Preamble:

In the Union Gas Rate Zone Underground Storage Plant table, column 2 provides additions in the total of ($17.6M).
We would like to understand the nature of these changes and the allocation to utility storage plant.

Question(s):

For each specific project over a million dollars that contribute to the additions, please provide:

a) A description of the project
b) A Board approval reference, if any
c) A specific description of the functionality created, improved or replaced as a result of the capital invested including:
    i) Any revision to storage space available
        1) If additional storage space, please provide how much space was allocated to utility operations or non-utility operations.
    ii) Any revision to deliverability available
        1) If additional deliverability, please provide how much space was allocated to utility operations or non-utility operations.
d) For each project, please define in gas being moved for non-utility storage contracts moves through the modified, upgraded or replaced facilities.
    i) The allocation of costs between utility and non-utility
    ii) the specific basis for the allocation approach
    iii) The reasoning associated with that allocation basis
e) Please describe the determination of the $6.0M in regulatory overheads including the determination and basis for allocation of regulatory overheads to the non-utility.

<u>Response:</u>

a) - d)

The following specific additions are greater than one million dollars. The remaining additions are comprised of several small projects.

All allocations of project costs between utility and non-utility or regulated and unregulated assets are based on the unregulated storage cost allocation studies previously approved by the OEB. The split between unregulated storage assets and regulated utility assets at each individual storage pool is updated annually to reflect additions and retirements that occurred throughout the prior year, for the purposes of allocating costs associated with capital maintenance of the assets.

As previously noted in EB-2022-0086[1], due to the integrated nature of the Dawn Hub, and as the Dawn Hub has grown over time, utility and non-utility space and molecules are inherently interconnected and cannot be separated operationally.

As a result, the projects listed below will serve both utility and non-utility operations. However, the cost allocation between utility and non-utility operations depends on the nature of the assets, including whether they replace existing assets and/or create new storage capacity. This is consistent with the current storage cost allocation methodology.

The costs shown below for each project exclude indirect overheads.

<u>Dawn-Cuthbert NPS 42 Replacement (IC 48257)</u>

- 2022 regulated capital additions to underground storage assets - $4,369,314
- The scope of this work includes the replacement of 700m of NPS42 pipeline between Dawn and Cuthbert Road Valve site and the installation of permanent in-line inspection (ILI) tool launcher and receiver facilities so they can be inspected with ILI tools.
- There is no OEB approval for the project.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

[1] EB-2022-0086, Exhibit I.SEC.18, part d).

NPS 12 Enniskillen Pool Retrofit (IC 1172/102661)

- 2022 regulated capital additions to underground storage assets - $1,035,814.
- The scope of this work includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities so they can be inspected with ILI tools.
- There is no OEB approval for the project.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 62% regulated and 38% unregulated based on the storage cost allocation methodology.

NPS 20 Rosedale Pool Retrofit (IC 1174/102663)

- 2022 regulated capital additions to underground storage assets - $1,035,814.
- The scope of this work includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities so they can be inspected with ILI tools.
- There is no OEB approval for the project.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 62% regulated and 38% unregulated based on the storage cost allocation methodology.

e) Enbridge Gas allocates capitalized overheads to individual plant assets based on forecasted capital expenditures for the corresponding year of spend. Note that in the Union Gas rate zones, capitalized overheads additions are presented in regulatory overhead plant asset accounts. Capitalized overheads are only applicable to regulated projects and would not be applicable to non-utility capital. Under US GAAP, these types of overheads costs would be expensed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

EB-2022-0110 Exhibit I.FRPO.7

Preamble:

In last year's proceeding, we asked descriptions of the projects for the rationale for the utility and non-utility allocations. While we received descriptions of the projects, we did not receive understanding of the rationales. As such, we are asking more specific questions for those projects described in response to FRPO.7 last year.

Question(s):

For each specific project over a million dollars that contribute to the additions, please provide:

a) A specific description of the functionality created, improved or replaced as a result of the capital invested including:
    i) Any revision to storage space available
        1) If additional storage space, please provide how much space was allocated to utility operations or non-utility operations.
    ii) Any revision to deliverability available
        1) If additional deliverability, please provide how much space was allocated to utility operations or non-utility operations.
b) For each project, please define in gas being moved for non-utility storage contracts moves through the modified, upgraded or replaced facilities.
    i) The allocation of costs between utility and non-utility
    ii) the specific basis for the allocation approach
    iii) The reasoning associated with that allocation basis
c) Please describe the determination of the $6.0M in regulatory overheads including the determination and basis for allocation of regulatory overheads to the non-utility.

Response:

a) - b)

All allocations of project costs between utility and non-utility or regulated and unregulated assets are based on the unregulated storage cost allocation studies previously approved by the OEB. The split between unregulated storage assets and regulated utility assets at each individual storage pool is updated annually to reflect additions and retirements that occurred throughout the prior year, for the purposes of allocating costs associated with capital maintenance of the assets.

As previously noted in EB-2022-0086[1], due to the integrated nature of the Dawn Hub, and as the Dawn Hub has grown over time, utility and non-utility space and molecules are inherently interconnected and cannot be separated operationally.

As a result, the projects listed below will serve both utility and non-utility operations. However, the cost allocation between utility and non-utility operations depends on the nature of the assets, including whether they replace existing assets and/or create new storage capacity. This is consistent with the current storage cost allocation methodology.

The costs shown below for each project exclude indirect overheads.

Corunna (SCOR) Meter Area Upgrade Phase 1 (IC 1811)

- 2021 capital expenditures were $14 million.
- Scope of work includes installation of Electrical Control building, replacement of meter run piping and install new header cross-over and isolation valves for Ladysmith and Dow-Moore pool lines and installation of west section of new NPS 30 A, B, C headers. Upon completion of Phase 1 and 2, this eliminates the flow induced vibration risk associated with the existing cross flow header. The new design eliminates thermal expansion stresses in piping that are exceeding allowable range as per CSA Z662. A reduction of fittings decreases the number of potential leak points
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

[1] EB-2022-0086 Exhibit I.SEC.18, part d.

Corunna (SCOR) Meter Area Upgrade Phase 2 (IC 500440)

- 2021 capital expenditures were $2.2 million.
- Scope of work includes replaced meter run piping and install new header cross-over and isolation valves for the Wilkesport, South Kimball, Seckerton, Corunna and Mid Kimball pool lines. Installed east section of new NPS 30 A, B, C headers and tie in east & west header sections.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

Wilkesport MOP Remediation (IC 101017)

- 2021 capital expenditures were $6.2 million.
- The scope of this work includes field verifications, replacement of specific pipe and fittings.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the replaced facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

NPS16 LAD-WLK Interconnect MOP (IC 502483)

- 2021 capital expenditures were $4.1 million.
- The scope of work is to replace the NPS 16 insulator at the Ladysmith-Wilkesport interconnect.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the replaced facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

<u>Strategic land purchases at two locations around the underground storage facilities (IC 735640/734521/734522)</u>

(1) Williams Property

- 2021 capital expenditures were $2 million.
- The purpose of the project is to purchase property and land.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- The project is 100% regulated based on the storage cost allocation methodology.

(2) Joyce/Maitland Property

- 2021 capital expenditures were $3 million
- The purpose of the project is to purchase property and land.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- The project expenditures were 100% regulated in 2021. During the asset unitization process, it was determined that a portion of the costs were related to the unregulated operations. Entries were completed in 2022 to allocate 33% of the project costs to unregulated, the remaining 67% is regulated.

<u>Wilksport (LWLK) Well Debris Filter (IC 500484/733789)</u>

- 2021 capital expenditures were $2.5 million.
- The scope of the project is to replace below grade in-line separator with above grade filter separator equipment.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the upgraded facilities.
- The project expenditures were 100% regulated in 2021. During the asset unitization process, it was determined that a portion of the costs were related to the unregulated operations. Entries were completed in 2022 to allocate 25% of the project costs to unregulated, the remaining 75% is regulated.

<u>NPS 16 Coveny Trans. Retrofit (IC 1908)</u>

- 2021 capital expenditures were $2.3 million.
- The project includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and replacement of pipeline segments with integrity issues that are identified through the inspections.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

<u>NPS 16 COV Gathering Retrofit (IC 1907)</u>

- 2021 capital expenditures were $2.2 million.
- The project includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and replacement of pipeline segments with integrity issues that are identified through the inspections.
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the modified facilities.
- The project is 100% regulated based on the storage cost allocation methodology.

<u>LLAD: Pipeline and Meter Station – Upgrade (IC 102893)</u>

- 2021 Capital expenditures were $6.2 million.
- The scope of work is installation of a flow control valve at the meter station along with required air systems and insulation.
- This project is part of the Storage Enhancement Delta Pressuring Phase 1 and includes various locations. (EB-2020-0256)
- There is no revision to storage space as a result of the project.
- There is no revision to deliverability as a result of the project.
- Gas being moved for non-utility storage contracts moves through the upgraded facilities.

- The project is 100% unregulated based on the storage cost allocation methodology.

c) Enbridge Gas believes this question is a duplication of Exhibit I.FRPO.3 part e) and notes that this is not relevant to the interrogatory question posed in EB-2022-0110 Exhibit I.FRPO.7.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 3 and EB-2022-0110 Exhibit I.FRPO.4

Preamble:

We would like to understand the cost changes and source of inter-legacy company transactions.

Question(s):

For line 21, please break-out the aggregate transactions between legacy EGD and UG into the respective lines 9 to 20 similar to FRPO. 4 from last year providing the last 3 years including 2022.

a) Please provide a description of S&T Transport Carbon Facility Collection transaction between legacy companies and drivers for differences over time.

b) Please describe why a distributor like EGI charges itself for a facilities charge when those carbon costs are already paid for by end use customers.

Response:

Table 1 provides a breakdown of transactions between the EGD Rate Zone and Union Rate Zones for year 2020, 2021 and 2022. Please note that all transactions below are EGD Rate Zone contracting with Union Rate Zone.

Table 1

Revenue from Regulated Transportation Services between legacy EGD and UG

Line No.	Particulars ($000s)	2020 Actual	2021 Actual	2022 Actual
		(a)	(b)	(c)
	Revenue from Regulated Transportation Services:			
1.	M12 Transportation	124,282	126,332	130,370
2.	M12-X Transportation	10,779	10,872	12,384
3.	C1 Long Term Transportation	-	-	-
4.	Rate 332: Gas Transmission	-	-	-
5.	C1 Short Term Transportation	-	53	16
6.	Gross Exchange Revenue	-	-	-
7.	Rate 331: Gas Transmission	-	-	-
8.	M13 Local Production	-	-	-
9.	M16 Transportation	407	332	374
10.	S&T: Transportation Carbon Facility Collection	677	890	1,423
11.	Other S&T Revenue	10	10	10
12.	Less: Elimination of charges between EGD and Union rate zones	-	-	-
13.	Total Regulated Transportation Revenue Net of Deferral	$136,155	$138,489	$144,576

a) The calculation of carbon facility charge is based on actual volumes multiplied by the approved carbon facility rate. The higher revenue is driven by higher carbon facility rate and higher volumes.

b) The approved facility carbon charge is applied to all customers within each respective rate class, regardless of whether it is an intercompany transaction. Since the facility carbon charge is based on forecasted volumes for all rate classes, those costs are not already paid for by in-franchise end-use customers. Ex-franchise customers contribute to the recovery of total facility-related carbon costs. Enbridge Gas files the calculation of the facility carbon charge as part of the annual Federal Carbon Pricing Program proceeding. The derivation of the facility carbon charge includes forecasted volumes related to in-franchise and ex-franchise services to recover the carbon compliance costs associated with expenses such as company-use fuel and compressor fuel.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, Appendix A
And EB-2022-0110 Exhibit I.FRPO.6

Preamble:

We would like to understand the volatility in line 10 over the deferred rebasing term. Last year's response did not provide the cost of each association's membership for which we asked so we are asking specifically for each organization's annual membership costs for each year.

Question(s):

For line 10, please provide a breakout of all organizational memberships and their respective costs in 2019 through 2022.

a) Please provide the value to ratepayers associated with the memberships included.

b) Please explain the fluctuations in those membership costs

Response:

Enbridge Gas is a member of a number of organizations representing various stakeholders within the industry. Total membership costs amounted to $3.8 million in 2019, $2.8 million in 2020, $2.6 million in 2021, and $2.1 million in 2022.

A complete list of each organization's annual membership costs is private and confidential in nature and would be sensitive to Enbridge Gas's industry partners.

In an attempt to be responsive, Enbridge Gas is expanding on the partial listing of membership affiliations provided last year:

- Canadian Gas Association
- Ontario Energy Association

- The Toronto Region Board of Trade
- Ottawa Board of Trade
- Ontario Chamber of Commerce
- Niagara Home Builders Association
- Energy Storage Canada
- Hydrogen Council
- MARS Discovery District
- Association of Municipalities of Ontario
- Canadian Manufacturers and Exporters
- Association of Energy Services
- Ontario Sustainable Energy Association
- Ontario Waste Management
- Association of Power Producers
- Canadian Biogas Association
- Utilization Technology Development
- Consumers Council of Canada
- Various Home Builders Associations

a) Participation in member-driven organizations allows Enbridge Gas to leverage industry partners by pooling resources to efficiently act on behalf of the sector. Representation at industry consultations, direct engagement with various levels of government, development of industry data, and sharing of best practices from across the industry are some examples of how leveraging membership adds value.

b) Membership costs remained relatively flat in 2020 and 2021. The reduction in membership costs from 2019 to 2020 was driven by productivity and integration savings achieved by pooling services and membership fees.

   In 2022, membership costs were lower than normal activity, however, the costs are expected to go back to the previous 2021 level for 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, Appendix A
And EB-2022-0110 Exhibit I.FRPO.6

Preamble:

We would like to understand the volatility in line 10 over the deferred rebasing term. Last year's response did not provide the cost of each association's membership for which we asked so we are asking specifically for each organization's annual membership costs for each year.

Question(s):

Please define and show the other components of line 10 over the 2019 to 2022 period.

Response:

Please see components of line 10 in Table 1.

Table 1

Donations and Memberships Expense

Line No.	Categories	2019 Actual ($M)	2020 Actual ($M)	2021 Actual ($M)	2022 Actual ($M)
1	Donations (Line 19)	3.0	0.7	3.6	1.1
2	Sponsorships	2.7	0.2	3.1	1.2
3	Membership	3.8	2.4*	2.6	2.1
4	LEAP Program	1.5	0.9	2.7	0
5	Exclude DSM (passthrough)	(0.9)	(0.9)	(0.7)	(0.8)
6		10.1	3.2	11.3	3.6

*Note: There is a $0.4 million difference in the 2020 membership costs (line 3) compared to what is reported in Exhibit I.FRPO.6 due to an accounting correction from the previous year.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 1, Page 24

Preamble:

We want to understand the appropriateness of the request for compensation for the reduction in Contract Demand (CD) for the turnback of CD of the customer.

Question(s):

In a table, for each legacy Union South, Union North and EGD rates zones, please provide CD and associated revenue of all contract customers embedded in rates in 2019 and the actual amount of CD and associated revenue for each year of the deferred rebasing period including on a forecast basis for the later years.

a) In a separate table, for each rate zone, please provide the year over year growth/decline in CD and associated revenue along with the proposed recoveries for this one customer on an actual and percentage revenue basis.

Response:

The inference FRPO is making in the question is that recovering lost revenue for IRP alternatives that utilize a reduced contract customer's firm CD is not appropriate. Enbridge Gas disagrees. Enbridge Gas conducts reverse open seasons with its contract rate customers to determine if one or more customers in a project area would reduce their firm CD to help defer or reduce the scope of a facility project. If one or more customers elect to reduce their firm CD, and the facility project is deferred or downsized as a result, then Enbridge should be able to recover the lost revenue related to the reduced firm CD, otherwise it would cost Enbridge Gas to implement the IRP alternative without cost recovery.

While the question above is not relevant to other IRP projects or this proceeding, Enbridge Gas has included the math requested to be responsive.

Please refer to Table 1 below for a summary of contract demand and contract demand revenue by rate zone, including the year over year trend and relative comparison to the customer turnback contract demand and revenue included within the IRP deferral.

Table 1

Summary of EGI Contract Demands & Associated Revenue

Line No.	Particulars	Col. 1 2019 Rates (1)	Col. 2 2019 Actual	Col. 3 2020 Actual	Col. 4 2021 Actual	Col. 5 2022 Actual	Col. 6 2023 Forecast
	Contract Demands (10^3m^3/day) (2)						
1.	EGD	235,448	239,422	247,855	256,000	264,515	270,859
2.	Union North	114,935	129,668	129,467	128,757	133,869	136,337
3.	Union South	286,624	419,436	436,419	453,667	475,782	481,163
4.	Total Contract Demands	637,007	788,526	813,741	838,424	874,166	888,360
5.	Year over Year Increase/(Decrease)			25,215	24,683	35,742	14,194
6.	Year over Year % Increase/(Decrease)			3%	3%	4%	2%
7.	Customer Turnback					14	173
8.	Turnback % of Total Contract Demand					0%	0%
	Contract Demand Revenues ($000's)						
9.	EGD	31,063	33,167	36,333	39,820	42,943	44,886
10.	Union North	22,506	26,438	27,833	28,148	29,630	31,578
11.	Union South	56,738	102,496	110,986	118,416	124,883	127,982
12.	Total Contract Demand Revenues	110,307	162,101	175,152	186,383	197,456	204,447
13.	Year over Year Increase/(Decrease)			13,051	11,232	11,072	6,991
14.	Year over Year % Increase/(Decrease)			8%	6%	6%	4%
15.	Customer Turnback Revenue					3	35
16.	Turnback % of Total Contract Demand Revenue					0%	0%

Notes

(1) Per EB-2019-0193, Exhibit F1, Tab 2, Schedule 5 and EB-2019-0193, Exhibit C, Tab 4, Schedule 5. EGD demands and revenues are based on approved 2018 Custom IR Framework and Union rate zone demands and revenues are based on approved 2013 Cost of Service volumes.

(2) Contract demands are the annual total of monthly contract demands parameters.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, Page 1

Question(s):

Please provide the EGI annual financial report for 2022.

Response:

Please refer to Attachment 1.

ENBRIDGE GAS INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2022

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE GAS INC.

Financial Reporting
Management of Enbridge Gas Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors is responsible for all aspects related to governance of the Company. The Company does not have an Audit Committee, having received an exemption from such requirement.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with US GAAP and to provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, have conducted an audit of the consolidated financial statements of the Company in accordance with Canadian generally accepted auditing standards and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

/s/ Michele E. Harradence	**/s/ Tanya M. Ferguson**
Michele E. Harradence	Tanya M. Ferguson
President	Vice President, Finance

February 10, 2023

Independent auditor's report

To the Shareholders of Enbridge Gas Inc.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Inc. and its subsidiaries (together, the Company) as at December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America (US GAAP).

What we have audited
The Company's consolidated financial statements comprise:

- the consolidated statements of earnings for the years ended December 31, 2022 and 2021;
- the consolidated statements of comprehensive income for the years ended December 31, 2022 and 2021;
- the consolidated statements of changes in equity for the years ended December 31, 2022 and 2021;
- the consolidated statements of cash flows for the years ended December 31, 2022 and 2021;
- the consolidated statements of financial position as at December 31, 2022 and 2021; and
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

pwc

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Ontario
February 10, 2023

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Operating revenues		
Gas commodity and distribution	**5,613**	3,996
Storage, transportation and other	**995**	897
Total operating revenues *(Note 4)*	**6,608**	4,893
Operating expenses		
Gas commodity and distribution costs	**3,679**	2,146
Operating and administrative	**1,227**	1,105
Depreciation and amortization	**690**	677
Total operating expenses	**5,596**	3,928
Operating income	**1,012**	965
Other income	**79**	43
Interest expense, net *(Note 10)*	**(423)**	(394)
Earnings before income taxes	**668**	614
Income tax expense *(Note 15)*	**(69)**	(63)
Earnings	**599**	551

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Earnings	**599**	551
Other comprehensive income, net of tax *(Note 12)*		
Change in unrealized gain on cash flow hedges	**68**	21
Reclassification to earnings of loss on cash flow hedges	**7**	12
Actuarial gain on other postretirement benefits (OPEB)	**29**	22
Reclassification to earnings of OPEB amounts	**(1)**	—
Other comprehensive income, net of tax	**103**	55
Comprehensive income	**702**	606

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Common shares *(Note 11)*		
Balance at beginning of year	**3,442**	3,517
Capital contribution	**800**	975
Return of capital	**(583)**	(1,050)
Balance at end of year	**3,659**	3,442
Additional paid-in capital		
Balance at beginning and end of year	**7,253**	7,253
Retained earnings/(deficit)		
Balance at beginning of year	**(324)**	(675)
Earnings	**599**	551
Common share dividends declared	**(104)**	(200)
Balance at end of year	**171**	(324)
Accumulated other comprehensive income/(loss) *(Note 12)*		
Balance at beginning of year	**(23)**	(78)
Other comprehensive income, net of tax	**103**	55
Balance at end of year	**80**	(23)
Total equity	**11,163**	10,348

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Operating activities		
Earnings	**599**	551
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**690**	677
Deferred income tax recovery *(Note 15)*	**(15)**	(15)
Net defined pension and OPEB costs	**(56)**	(24)
Expected credit loss	**20**	14
Other	**11**	10
Changes in operating assets and liabilities *(Note 17)*	**(1,171)**	(473)
Net cash provided by operating activities	**78**	740
Investing activities		
Capital expenditures	**(1,482)**	(1,308)
Additions to intangible assets	**(39)**	(72)
Proceeds from disposition	**12**	—
Net cash used in investing activities	**(1,509)**	(1,380)
Financing activities		
Net change in short-term borrowings	**481**	394
Demand loan from affiliate *(Note 18)*	**318**	—
Term note issuances, net of issue costs	**645**	896
Term note repayments *(Note 10)*	**(125)**	(375)
Common share dividends	**(104)**	(200)
Return of capital	**(583)**	(1,050)
Capital contribution received	**800**	975
Net cash provided by financing activities	**1,432**	640
Net change in cash	**1**	—
Cash at beginning of year	**9**	9
Cash at end of year	**10**	9
Supplementary cash flow information		
Cash paid/(received) for income taxes	**1**	(5)
Cash paid for interest, net of amounts capitalized	**400**	374
Property, plant and equipment and intangibles non-cash accruals	**80**	75

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2022**	2021
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash	**10**	9
Accounts receivable and other *(Note 6)*	**2,346**	1,228
Accounts receivable from affiliates	**191**	156
Gas inventory	**1,424**	897
	3,971	2,290
Property, plant and equipment, net *(Note 7)*	**17,601**	16,662
Intangible assets, net *(Note 8)*	**175**	177
Deferred amounts and other assets	**2,996**	2,677
Goodwill	**4,784**	4,784
Total assets	**29,527**	26,590
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 10)*	**1,996**	1,515
Accounts payable and other *(Note 9)*	**1,864**	1,458
Accounts payable to affiliates	**195**	113
Current portion of long-term debt *(Note 10)*	**352**	126
Demand loan from affiliate *(Note 18)*	**318**	—
	4,725	3,212
Long-term debt *(Note 10)*	**9,625**	9,352
Other long-term liabilities	**2,160**	2,012
Deferred income taxes *(Note 15)*	**1,854**	1,666
	18,364	16,242
Commitments and contingencies *(Note 19)*		
Equity		
Share capital *(Note 11)*		
Common shares *(522 outstanding at December 31, 2022 and 2021)*	**3,659**	3,442
Additional paid-in capital	**7,253**	7,253
Retained earnings/(deficit)	**171**	(324)
Accumulated other comprehensive income/(loss) *(Note 12)*	**80**	(23)
	11,163	10,348
Total liabilities and equity	**29,527**	26,590

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

/s/ Michele E. Harradence
Michele E. Harradence
Director

/s/ William T. Yardley
William T. Yardley
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

The terms "we", "our", "us" and "Enbridge Gas" as used in these financial statements refer collectively to Enbridge Gas Inc. and its subsidiaries unless the context suggests otherwise. Enbridge Gas is a wholly-owned indirect subsidiary of Enbridge Inc. (Enbridge). Enbridge provides administrative and general support services to us.

Enbridge Gas is a rate-regulated natural gas distribution utility with storage and transmission services, which serves residential, commercial and industrial customers throughout Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (US GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

We are permitted to prepare our consolidated financial statements in accordance with US GAAP for purposes of meeting Canadian continuous disclosure requirements under an exemption granted by Canadian securities regulators until the earliest of January 1, 2027, the first day of our financial year that commences if and after we cease to have activities subject to rate regulation, or the effective date prescribed by the International Accounting Standards Board for the application of a Mandatory Rate-regulated Standard specific to entities with activities subject to rate regulation.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: variable consideration included in revenue *(Note 4);* carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues; estimates of revenue; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 7)*; amortization rates and carrying value of intangible assets *(Note 8)*; measurement of goodwill; fair value of asset retirement obligations (ARO); fair value of financial instruments *(Note 13)*; provisions for income taxes *(Note 15)*; assumptions used to measure retirement benefits and OPEB *(Note 16)*; and commitments and contingencies *(Note 19)*. Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

REGULATION

Our utility operations within Ontario are regulated by the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates and amounts collected from customers in advance of costs being incurred. Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. The regulator’s future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which we operate. To the extent that the regulator’s actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates. We believe that the recovery of our regulatory assets as at December 31, 2022 is probable over the periods described in *Note 5 - Regulatory Matters*.

With the approval of the regulator, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

REVENUE RECOGNITION

Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations for the distribution, storage, transportation and sale of natural gas. For distribution and transportation service arrangements, where the services are simultaneously received and consumed by the customer, revenues are recorded based on regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas. Revenues from storage services are recognized as the storage services are provided.

A significant portion of our operations are subject to regulation and, accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator, which are accounted for under Accounting Standards Codification (ASC) 980 *Regulated Operations*.

PUSH-DOWN ACCOUNTING

Enbridge Gas Distribution Inc. (EGD) elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted US GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by EGD. Upon adopting push-down accounting, the historical cost of EGD’s property, plant and equipment and related accounts were adjusted by the remaining unamortized fair value adjustment.

We have also applied push-down accounting with respect to the accounts of Union Gas Limited (Union Gas). The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge's historical cost as at February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

We use derivative financial instruments to manage our exposure to changes in foreign exchange rates and interest rates. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges. There were no outstanding derivative instruments relating to fair value or net investment hedges as at December 31, 2022 and 2021.

Cash Flow Hedges

We use cash flow hedges to manage our exposure to changes in foreign exchange rates and interest rates related to our unregulated storage revenue. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a reduction to Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

INCOME TAXES

Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

FOREIGN CURRENCY TRANSACTIONS

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge Gas operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the translation of monetary assets and liabilities are included in earnings in the period in which they arise.

CASH

We combine cash and bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements.

RECEIVABLES AND CURRENT EXPECTED CREDIT LOSSES

Accounts receivable and other are measured at cost. Interest income is recognized in earnings as it is earned with the passage of time. For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations.

NATURAL GAS IMBALANCES

The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received from, and delivered for, customers. As settlement of imbalances are in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. All natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

GAS INVENTORY

Gas inventories consist of natural gas held in storage. Natural gas held in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection, as approved by the OEB.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including an allowance for interest incurred during construction as authorized by the regulator. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the regulator. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation. Gains and losses on the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the regulator, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the regulator.

LEASES

We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily consist of costs our regulatory authority have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; the fair value adjustment to long-term debt; the difference between the actual cost and approved cost of natural gas reflected in rates; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs. We capitalize costs incurred during the application development stage of internal use software projects. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends and industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of goodwill and comparing that value to its carrying value. If the carrying value, including allocated goodwill, exceeds fair value, goodwill impairment is measured at the amount by which the carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value is estimated using a discounted cash flow technique. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income and rate base, rate base multiple, capital expenditures and working capital levels.

Due to changes in the macroeconomic environment which has led to a rise in interest rates, we performed a quantitative assessment as at December 1, 2022. The goodwill impairment assessment did not result in an impairment charge.

IMPAIRMENT
We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds its expected undiscounted cash flows, we will calculate fair value based on the discounted cash flows and write the asset down to the extent that the carrying value exceeds the fair value.

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. Fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

PENSION AND OTHER POSTRETIREMENT BENEFITS
We provide benefits through defined benefit and defined contribution pension plans, as well as defined benefit OPEB plans.

Obligations and net periodic benefit costs for defined benefit pension and OPEB plans are estimated using the projected unit credit method, which is based on years of service, as well as our best estimates of actuarial assumptions such as discount rates, future salary levels, other cost escalations, employees' retirement ages, and mortality.

We determine discount rates using market yields of high-quality corporate bonds with maturities that approximate the estimated timing of future benefit payments.

Plan assets are measured at fair value. The expected return on plan assets is determined using the long-term target asset mixes in our investment policies and long-term market expectations.

Actuarial gains and losses arise from the difference between the actual and expected return on plan assets, and changes in actuarial assumptions such as discount rates. Periodic net actuarial gains and losses and prior service costs are accumulated and presented as follows in the Consolidated Statements of Financial Position:

- as a component of AOCI, for our defined benefit OPEB plans; and
- as a component of Deferred amounts and other assets and/or Other long-term liabilities, for our defined benefit pension plans, to the extent that the net actuarial gains and losses and prior service costs have been permitted or are expected to be permitted by the regulator, to be recovered through future rates.

Net periodic benefit cost is recognized in earnings and includes:

- current service cost;
- interest cost;
- expected return on plan assets;
- amortization of prior service costs over the expected average remaining service life of the plans' active employee group; and
- amortization of net actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the fair value of plan assets, over the expected average remaining service life of the plans' active employee group.

We also record regulatory adjustments for the difference between net periodic benefit costs for accounting versus ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be recovered from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, our contributions are expensed when the contribution occurs.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during the year ended December 31, 2022.

ADOPTION OF NEW ACCOUNTING STANDARDS

Disclosures About Government Assistance

Effective January 1, 2022, we adopted Accounting Standards Update (ASU) 2021-10 on a prospective basis. The new standard was issued in November 2021 to increase the transparency of government assistance to business entities. The ASU adds new disclosure requirements for transactions with governments that are accounted for using a grant or contribution accounting model by analogy. The required disclosures include information about the nature of transactions, accounting policy applied, impacted financial statement line items and significant terms and conditions. The adoption of this ASU did not have a material impact on our consolidated financial statements.

4. REVENUES

REVENUE FROM CONTRACTS WITH CUSTOMERS

Major Services

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Gas commodity and distribution revenue - residential	**3,771**	2,778
Gas commodity and distribution revenue - commercial and industrial	**1,832**	1,208
Storage revenue	**176**	156
Transportation revenue	**791**	686
Other revenue	**76**	71
Total revenue from contracts with customers	**6,646**	4,899
Other[1]	**(38)**	(6)
Total revenues	**6,608**	4,893

1 Primarily relates to the effects of rate-regulated accounting.

We disaggregate revenues into categories which represent our principal performance obligations. These revenue categories also represent the most significant revenue streams, and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Contract Receivables	Contract Liabilities
(millions of Canadian dollars)		
Balance as at December 31, 2022	**1,359**	**—**
Balance as at December 31, 2021	824	17

Contract receivables represent an unconditional right to consideration where only the passage of time is required before payment of consideration is due, and consist of trade accounts receivable, unbilled revenue and other accrued receivable balances. Contract receivables also consist of trade accounts receivable and unbilled revenue balances for the collection of certain federal carbon levy unit rates, for which we act as an agent.

Contract liabilities represent payments received for performance obligations which have not been fulfilled under our equal monthly payment plan. Revenue recognized during the year ended December 31, 2022 related to obligations under the equal monthly payment plan that existed at December 31, 2021 was $17 million.

Performance Obligations

Revenue category	Nature of Performance Obligation
Gas commodity and distribution revenue	• Supply and delivery of natural gas to customers
Storage and transportation revenue	• Storage and transportation of natural gas on behalf of customers
Other revenue	• Other billing and service fees

There was no material revenue recognized during the year ended December 31, 2022 from performance obligations satisfied in previous periods.

Payment Terms
Payments from distribution customers are received on a continuous basis based on established billing cycles. Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. Payments from storage customers are received monthly under long-term storage capacity contracts. Payments from transportation customers are received on a continuous basis based on established billing cycles or monthly under long-term transportation capacity contracts.

Revenue to be Recognized from Unfulfilled Performance Obligations
Total revenue from performance obligations expected to be fulfilled in future periods is $643 million, of which $354 million is expected to be recognized during the year ending December 31, 2023.

The performance obligations above reflect revenue expected to be recognized in future periods from unfulfilled performance obligations pursuant to contracts with customers for the purchase of natural gas distribution, storage and transportation services. Certain revenues are excluded from the amounts above under the following ASC 606 optional exemptions:

- revenues, such as flow-through costs charged to customers, which are recognized at the amount for which we have the right to invoice our customers; and
- revenue from contracts with customers that have an original expected duration of one year or less.

Variable consideration is also excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be reasonably estimated.

A significant portion of our operations are subject to regulation. Accordingly, the amounts above, in addition to revenues that are not regulated, only include revenue for which the underlying rate has been approved by regulation, where applicable. The revenues excluded from the amounts above could represent a significant portion of our overall revenues and revenue from contracts with customers.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE

Revenue Recognition

Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations as described above. Distribution and transportation service revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Due to regulatory mechanisms, there are circumstances where revenues recognized do not match the amounts billed. Under such circumstances, revenue is recognized in a manner that is consistent with the underlying rate setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator.

Recognition and Measurement of Revenues

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Revenue from products and services transferred over time[1]	**6,571**	4,829
Revenue from products transferred at a point in time[2]	**75**	70
Total revenue from contracts with customers	**6,646**	4,899

1 Revenue from distribution, storage and transportation services.
2 Primarily from Other revenues.

Performance Obligations Satisfied Over Time

For arrangements involving the distribution and transportation of natural gas, where the services are simultaneously received and consumed by the customer, we recognize revenue over time using an output method based on volumes of commodities delivered. The measurement of the volumes delivered corresponds directly to the benefits received by the customers during that period. Revenue from storage services are recognized as the services are provided.

Determination of Transaction Prices

Prices for distribution and transportation services and regulated storage services are prescribed by regulation. Fees for unregulated storage services are determined through negotiations with customers and are based on market rates.

Prices for natural gas sold are driven by market prices and the Quarterly Rate Adjustment Mechanism (QRAM) in place that allows for rates to reflect changes in natural gas prices, subject to regulatory approval.

5. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under US GAAP for non-regulated entities. See *Note 2 - Significant Accounting Policies* for further discussion.

We are regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act*, (1998), which is part of a package of legislation known as the *Energy Competition Act*, (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario.

RATE APPROVALS

Our distribution rates, commencing in 2019, are set under a five-year Incentive Regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires us to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved return on equity.

Under the current OEB-authorized rate structure for our business, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of temporary differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since most of these temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the related assets. In the absence of rate-regulated accounting, this regulatory Deferred income taxes balance and the related earnings impact would not be recorded.

PURCHASE GAS VARIANCE

The Purchase Gas Variance Account (PGVA) captures the difference between actual and forecasted natural gas prices reflected in rates. Account balances are typically recovered or refunded over a prospective 12-month period through QRAM applications. Due to the significant increase in natural gas prices, the approvals have also included rate mitigation plans intended to ease bill impacts to ratepayers. Specifically, the approved rate mitigation plans extended the PGVA recovery period from 12 months to 24 months in certain applications.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position:

December 31,	**2022**	2021	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Purchase gas variance	**190**	15	2023
Other current regulatory assets	**266**	67	2023
Total current regulatory assets[1] *(Note 6)*	**456**	82	
Long-term regulatory assets			
Deferred income taxes	**1,696**	1,532	Various
Long-term debt[2] *(Note 10)*	**283**	307	2046
Purchase gas variance	**244**	215	2024
Accounting policy changes[3]	**219**	157	Various
Transition impact of accounting changes[4]	**40**	49	2032
Pension plan receivable[5]	**—**	26	Various
Other long-term regulatory assets	**2**	91	Various
Total long-term regulatory assets[1]	**2,484**	2,377	
Total regulatory assets	**2,940**	2,459	
Current regulatory liabilities			
Other current regulatory liabilities	**128**	61	2023
Total current regulatory liabilities[6] *(Note 9)*	**128**	61	
Long-term regulatory liabilities			
Future removal and site restoration reserves[7]	**1,615**	1,543	Various
Pension plan payable[5]	**230**	—	Various
Other long-term regulatory liabilities	**90**	111	Various
Total long-term regulatory liabilities[6]	**1,935**	1,654	
Total regulatory liabilities	**2,063**	1,715	

1 *Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.*

2 *Represents our regulatory offset to the fair value adjustment to debt acquired in Enbridge's merger with Spectra Energy Corp. (Spectra Energy) and pushed down to Enbridge Gas. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.*

3 *This deferral primarily consists of unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas, relating to the period up to Enbridge's merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income and recovered in rates, as previously approved by the OEB.*

4 *Represents our right to recover costs resulting from the adoption of the accrual basis of accounting for pension and OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the balance as at December 31, 2012 is to be collected in rates over a 20 year period, commencing in 2013.*

5 *Represents the regulatory offset to our pension liability/asset to the extent that it is expected to be included in regulator-approved future rates and refunded to or recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense/income would be recorded in earnings and OCI.*

6 *Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.*

7 *Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Gas Inventories

Natural gas held in storage is recorded in inventory at the reference prices approved by the OEB in the determination of customers' system supply rates. In prior years, Gas inventory included costs related to storage injection and demand charges that, consistent with the regulatory recovery pattern, were recorded in gas inventories during our off-peak months and charged to gas costs during the peak winter months. As of December 31, 2022 we transferred $63 million related to storage injection and demand costs from Gas inventory to the Accounting policy changes deferral account where the balance will reside until we request disposal at the end of current rebasing term. Included in Gas inventory as at December 31, 2021 was $61 million related to storage injection and demand costs. In the absence of rate-regulated accounting, these costs would be expensed as incurred, and inventory would be recorded at the lower of cost or market value.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2022**	2021
(millions of Canadian dollars)		
Trade receivables and unbilled revenues, net[1]	**1,550**	953
Regulatory assets *(Note 5)*	**456**	82
Gas imbalances	**177**	101
Rebillables receivable	**61**	45
Other	**102**	47
	2,346	1,228

1 Net of allowance for expected credit losses of $71 million as at December 31, 2022 (2021 - $55 million).

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2022**	2021
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas transmission	2.4%	**1,960**	1,854
Gas mains, services and other	2.6%	**14,219**	13,354
Compressors, meters and other operating equipment	4.3%	**3,538**	3,361
Storage	2.6%	**1,145**	1,065
Land and right-of-way[1]	0.9%	**413**	375
Vehicles, office furniture, equipment and other buildings and improvements	9.5%	**511**	453
Under construction	—%	**319**	263
		22,105	20,725
Accumulated depreciation		**(4,954)**	(4,464)
		17,151	16,261
Unregulated property, plant and equipment			
Gas mains, services and other	5.3%	**13**	13
Compressors, meters and other operating equipment	1.3%	**46**	42
Storage	2.8%	**413**	374
Land and right-of-way[1]	1.5%	**40**	38
Vehicles, office furniture, equipment and other buildings and improvements	—%	**13**	—
Under construction	—%	**48**	37
		573	504
Accumulated depreciation		**(123)**	(103)
		450	401
Property, plant and equipment, net		**17,601**	16,662

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.

Depreciation expense, including amounts collected for future removal and site restoration costs, was $638 million for the year ended December 31, 2022 (2021 - $606 million).

Included within depreciation expense is $22 million in incremental depreciation resulting from push-down accounting for the years ended December 31, 2022 and 2021 *(Note 2)*.

8. INTANGIBLE ASSETS

December 31,	**2022**	2021
(millions of Canadian dollars)		
Software and customer information system[1]	**466**	515
Less: Accumulated amortization	**(291)**	(338)
Intangible assets, net	**175**	177

1 The weighted average amortization rate for the years ended December 31, 2022 and 2021 was 11.3% and 12.8%, respectively.

Intangible assets include $21 million of work-in-progress as at December 31, 2022 (2021 - $26 million). Amortization expense for intangible assets for the years ended December 31, 2022 and 2021 was $52 million and $71 million, respectively. The following table presents our expected amortization expense associated with existing intangible assets for the years indicated as follows:

	2023	2024	2025	2026	2027
(millions of Canadian dollars)					
Forecast of amortization expense	54	23	22	18	12

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2022**	2021
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	**742**	638
Federal carbon program liability	**333**	242
Gas imbalances	**199**	124
Taxes payable	**169**	99
Construction payables and contractor holdbacks	**80**	88
Interest payable	**96**	87
Regulatory liabilities *(Note 5)*	**128**	61
Other	**117**	119
	1,864	1,458

10. DEBT

December 31,	Weighted Average Interest Rate[2]	Maturity	**2022**	2021
(millions of Canadian dollars)				
Medium-term notes	4.1%	2023 - 2052	**9,535**	9,010
Debentures	9.1%	2024 - 2025	**210**	210
Commercial paper and credit facility draws	4.5%	2024	**2,000**	1,515
Other[1]			**(55)**	(49)
Fair value adjustment from push down accounting *(Note 2)*			**283**	307
Total debt			**11,973**	10,993
Current maturities			**(352)**	(126)
Short-term borrowings			**(1,996)**	(1,515)
Long-term debt			**9,625**	9,352

1 Other consists of unamortized discounts, premiums and debt issuance costs.
2 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2022.

As at December 31, 2022, all outstanding debt was unsecured.

CREDIT FACILITIES

We actively manage our bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of our external credit facility at December 31, 2022:

	Maturity	Total Facility	Draws[2]	Available
(millions of Canadian dollars)				
364 day extendible credit facility	2024[1]	**2,000**	**2,000**	**—**

1 Maturity date is inclusive of the one-year term out provision.
2 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

In July 2022, we extended our 364 day extendible credit facility to July 2024, which includes a one-year term out provision from July 2023.

The credit facility carries a standby fee of 0.1% on the unused portion and the draws bear interest at market rates.

In addition to this committed credit facility, we had access to Enbridge's demand letter of credit facilities totaling $1.0 billion as at December 31, 2022 and 2021. As at December 31, 2022, $7 million (2021 - $15 million) of letters of credit were issued by us.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2022, we completed the following long-term debt issuances totaling $650 million:

Issue Date	Description	Principal Amount
(millions of Canadian dollars)		
August 2022	4.15% medium-term notes due August 2032	$325
August 2022	4.55% medium-term notes due August 2052	$325

LONG-TERM DEBT REPAYMENT

During the year ended December 31, 2022, we completed the following long-term debt repayment:

Repayment Date	Description	Principal Amount
(millions of Canadian dollars)		
April 2022	4.85% medium-term notes	$125

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. We are in compliance with all terms and conditions of our committed credit facility agreement and our Trust Indenture as at December 31, 2022.

INTEREST EXPENSE

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Debentures and term notes	**389**	392
Commercial paper and credit facility draws	**47**	9
Interest on loan from affiliate[1]	**2**	—
Capitalized interest	**(15)**	(7)
	423	394

1 Interest on loan from affiliate is with Enbridge Inc.

11. SHARE CAPITAL

As at December 31, 2022, our authorized share capital consisted of an unlimited number of common shares with no par value and an unlimited number of preference shares. Our Class A and Class B common shares are held by Enbridge Energy Distribution Inc. and Great Lakes Basin Energy LP, respectively. Both classes of common shares are identical in every respect, and dividends cannot be paid to one class without paying dividends to the other. As at December 31, 2022 and 2021, no preference shares were issued and outstanding.

COMMON SHARES

	2022		2021	
December 31,	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Class A				
Balance at beginning of year	**282**	**2,596**	282	2,636
Capital contribution	**—**	**432**	—	527
Return of capital	**—**	**(315)**	—	(567)
	282	**2,713**	282	2,596
Class B				
Balance at beginning of year	**240**	**846**	240	881
Capital contribution	**—**	**368**	—	448
Return of capital	**—**	**(268)**	—	(483)
	240	**946**	240	846
Balance at end of year	**522**	**3,659**	522	3,442

The capital contribution and return of capital transactions to the stated capital of Class A and Class B common shares had no impact on the total shares outstanding.

12. COMPONENTS OF AOCI

Changes in AOCI for the year ended December 31, 2022 and 2021 are as follows:

	2022		
	Cash Flow Hedges	OPEB Adjustment	Total
(millions of Canadian dollars)			
Balance at January 1, 2022	**(31)**	**8**	**(23)**
Other comprehensive income retained in AOCI	**93**	**39**	**132**
Other comprehensive loss/(income) reclassified to earnings	**10**	**(1)**	**9**
	72	**46**	**118**
Tax impact			
Income tax on amounts retained in AOCI	**(25)**	**(10)**	**(35)**
Income tax on amounts reclassified to earnings	**(3)**	**—**	**(3)**
	(28)	**(10)**	**(38)**
Balance at December 31, 2022	**44**	**36**	**80**

	2021		
	Cash Flow Hedges	OPEB Adjustment	Total
(millions of Canadian dollars)			
Balance at January 1, 2021	(64)	(14)	(78)
Other comprehensive income retained in AOCI	29	31	60
Other comprehensive loss reclassified to earnings	17	—	17
	(18)	17	(1)
Tax impact			
Income tax on amounts retained in AOCI	(8)	(9)	(17)
Income tax on amounts reclassified to earnings	(5)	—	(5)
	(13)	(9)	(22)
Balance at December 31, 2021	(31)	8	(23)

13. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

Our earnings, cash flows and other OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by our customers.

Foreign Exchange Risk

Foreign exchange risk is the risk of gain or loss due to the volatility of currency exchange rates. We generate certain revenues, incur expenses and hold cash balances that are denominated in United States (US) dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from US dollar exchange rate variability.

We have implemented a policy to hedge a portion of our US dollar denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated US dollar denominated revenues and to manage variability in cash flows.

A portion of our natural gas purchases are denominated in US dollars and, as a result, there is exposure to fluctuations in the exchange rate of the US dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to customers, therefore, we have no net exposure to movements in the foreign exchange rate on natural gas purchases.

Interest Rate Risk

Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. As at December 31, 2022, we do not have any floating-to-fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating-to-fixed interest rate swaps with an average swap rate of 2.6%.

TOTAL DERIVATIVE INSTRUMENTS

We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on financial derivative asset positions outstanding with these counterparties in those particular circumstances.

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments, as well as the maximum potential settlement amounts in the event of the specific circumstances described above. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2022	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts receivable from affiliates					
Interest rate contracts	**79**	**—**	**79**	**—**	**79**
	79	**—**	**79**	**—**	**79**
Total net derivative asset					
Interest rate contracts	**79**	**—**	**79**	**—**	**79**
	79	**—**	**79**	**—**	**79**

December 31, 2021	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts receivable from affiliates					
Interest rate contracts	14	—	14	—	14
	14	—	14	—	14
Deferred amounts and other assets					
Interest rate contracts	12	—	12	—	12
	12	—	12	—	12
Total net derivative asset					
Interest rate contracts	26	—	26	—	26
	26	—	26	—	26

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

December 31, 2022	2022	2023	2024	2025	2026	Thereafter	Total
(millions of Canadian dollars)							
Interest rate contracts - long-term debt	**—**	**900**	**—**	**—**	**—**	**—**	**900**

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on our consolidated earnings and comprehensive income, before the effect of income taxes.

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Amount of unrealized gain recognized in OCI		
Interest rate contracts	**93**	29
	93	29
Amount of loss reclassified from AOCI to earnings		
Interest rate contracts[1]	**10**	17
	10	17

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

We estimate that a gain of $7 million of AOCI related to unrealized cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest and foreign exchange rates in effect when derivative contracts, that are currently outstanding, mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 12 months as at December 31, 2022.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments, as they become due. In order to manage this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under the committed credit facility and long-term debt, which includes debentures and medium-term notes and, if necessary, additional liquidity is available through intercompany transactions with our ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable us to fund all anticipated requirements. We maintain a current medium-term note shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. We also maintain a committed credit facility with a diversified group of banks and institutions. We are in compliance with all of the terms and conditions of our committed credit facility as at December 31, 2022. As a result, the credit facility is available to us and the banks are obligated to fund us under the terms of the facility.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. We are primarily exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by our large and diversified customer base and the ability to recover an estimate for expected credit losses for utility operations through the rate-making process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default of receivables. Generally, we classify receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which generally require payment in full within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the expected credit loss, which totaled $71 million as at December 31, 2022 (December 31, 2021 - $55 million).

Our expected credit loss is determined based on historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations, using a loss allowance matrix. This estimate is revised each reporting period to reflect current expectations. When we have determined that collection efforts are unlikely to be successful, amounts charged to the expected credit loss account are applied against the impaired accounts receivable.

Entering into derivative financial instruments may also result in exposure to credit risk. We enter into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. As at December 31, 2022, we have $79 million (December 31, 2021 - $26 million) in credit concentrations and credit exposure with Enbridge and its affiliates.

Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair values of financial instruments reflect our best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. We do not have any derivative instruments classified as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps, for which observable inputs can be obtained.

As at December 31, 2022, we had Level 2 derivative assets with a fair value of $79 million (December 31, 2021 - $26 million).

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable, or where the observable data does not support a significant portion of the derivative's fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. We do not have any derivative instruments classified as Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value, including discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, we use observable market prices (interest, foreign exchange and natural gas) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS
The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. As at December 31, 2022, our long-term debt, including the current portion, had a carrying value of $9.7 billion (December 31, 2021 - $9.2 billion) before debt issuance costs and a fair value adjustment from push down accounting, and a fair value of $8.9 billion (December 31, 2021 - $10.4 billion).

The fair value of financial assets and liabilities, other than derivative instruments and long-term debt, approximate their carrying value due to the short period to maturity.

14. LEASES

LESSEE
We incur operating lease payments related to natural gas transportation, storage and real estate assets. These lease agreements have remaining lease terms of 1 year to 15 years, some of which include options to terminate at our discretion.

For the years ended December 31, 2022 and 2021, we incurred operating lease expenses of $9 million and $8 million, respectively. Operating lease expenses are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2022 and 2021, operating lease payments made to settle lease liabilities were $9 million and $9 million, respectively. Operating lease payments are reported within Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Consolidated Statements of Financial Position Information

December 31,	**2022**	2021
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases		
Operating lease right-of-use assets, net[1]	**48**	49
Operating lease liabilities - current[2]	**8**	6
Operating lease liabilities - long-term[3]	**40**	43
Total operating lease liabilities	**48**	49
Weighted average remaining lease term		
Operating leases	**7 years**	8 years
Weighted average discount rate		
Operating leases	**3.1%**	3.1%

1 *Right-of-use assets are reported within Deferred amounts and other assets in the Consolidated Statements of Financial Position.*
2 *Current lease liabilities are reported within Accounts payable and other and Accounts payable to affiliates in the Consolidated Statements of Financial Position.*
3 *Long-term lease liabilities are reported within Other long-term liabilities in the Consolidated Statements of Financial Position.*

As at December 31, 2022, we have lease commitments as detailed below:

	Operating leases
(millions of Canadian dollars)	
2023	**9**
2024	**8**
2025	**8**
2026	**8**
2027	**7**
Thereafter	**13**
Total undiscounted lease payments	**53**
Less imputed interest	**(5)**
Total operating lease liabilities	**48**

LESSOR

We receive revenues from operating and sales-type leases primarily related to natural gas equipment and real estate assets. Our lease agreements have remaining lease terms of 4 years to 20 years as at December 31, 2022.

As at December 31, 2022, the following table sets out future lease payments to be received under operating lease and sales-type lease contracts where we are the lessor:

	Operating leases	Sales-type leases
(millions of Canadian dollars)		
2023	**2**	**2**
2024	**1**	**2**
2025	**1**	**2**
2026	**1**	**2**
2027	**1**	**2**
Thereafter	**2**	**18**
Future lease payments to be received	**8**	**28**

15. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Earnings before income taxes	**668**	614
Canadian federal statutory income tax rate	**15%**	15%
Expected federal taxes at statutory rate	**100**	92
Increase/(decrease) resulting from:		
Provincial income taxes	**(39)**	(1)
Effects of rate-regulated accounting[1]	**(62)**	(54)
Part VI.1 tax, net of federal Part I deduction[1]	**76**	30
Other[2]	**(6)**	(4)
Income tax expense	**69**	63
Effective income tax rate	**10.3%**	10.3%

1 The provincial tax component of these items is included in Provincial income taxes above.
2 Includes miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals and entertainment and true-up prior year estimates to reflect the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

For 2022 and 2021, our earnings before income tax are exclusively from Canadian operations. We are subject to taxation in Canada only.

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Current income tax expense	**84**	78
Deferred income tax recovery	**(15)**	(15)
Income tax expense	**69**	63

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(1,823)**	(1,697)
Regulatory assets	**(452)**	(409)
Deferrals	**(27)**	(8)
Pension and OPEB plans	**(42)**	(14)
Financial instruments	**(16)**	—
Other	**(4)**	(7)
Total deferred income tax liabilities	**(2,364)**	(2,135)
Deferred income tax assets		
Future removal and site restoration reserves	**433**	413
Minimum tax credits	**71**	44
Financial instruments	**—**	12
Loss carryforwards	**6**	—
Total deferred income tax assets	**510**	469
Net deferred income tax liabilities	**(1,854)**	(1,666)

The material jurisdiction in which we are subject to potential examinations within Canada is Federal only. We are open to examination by Canadian tax authorities for 2017 to 2022 tax years and are currently under examination for income tax matters in Canada for 2017 to 2019 tax years.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**15**	34
Gross decreases for tax positions of prior year	**(6)**	(16)
Lapses of statute of limitations	**(3)**	(3)
Unrecognized tax benefits at end of year	**6**	15

The unrecognized tax benefits as at December 31, 2022, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2022 and 2021 included no amounts of interest and penalties. As at December 31, 2022 and 2021, the accrued interest and penalties remained at $1 million for both periods.

16. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We provide pension benefits, covering substantially all employees, through contributory and non-contributory registered defined benefit and defined contribution pension plans. We also provide non-registered pension benefits for certain employees through supplemental non-contributory defined benefit pension plans.

Defined Benefit Pension Plan Benefits

Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits

Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

OTHER POSTRETIREMENT BENEFIT PLANS

We provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees, through unfunded defined benefit OPEB plans.

BENEFIT OBLIGATIONS, PLAN ASSETS AND FUNDED STATUS

The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension and OPEB plans:

	Pension		OPEB	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Change in benefit obligation				
Benefit obligation at beginning of year	**2,386**	2,532	**157**	186
Service cost	**60**	63	**2**	3
Interest cost	**64**	51	**4**	4
Participant contributions	**13**	13	**—**	—
Actuarial gain[1]	**(528)**	(161)	**(39)**	(31)
Benefits paid	**(109)**	(112)	**(5)**	(5)
Benefit obligation at end of year[2]	**1,886**	2,386	**119**	157
Change in plan assets				
Fair value of plan assets at beginning of year	**2,415**	2,219	**—**	—
Actual return/(loss) on plan assets	**(129)**	258	**—**	—
Employer contributions	**37**	37	**5**	5
Participant contributions	**13**	13	**—**	—
Benefits paid	**(109)**	(112)	**(5)**	(5)
Fair value of plan assets at end of year	**2,227**	2,415	**—**	—
Overfunded/(underfunded) status at end of year	**341**	29	**(119)**	(157)
Presented as follows:				
Deferred amounts and other assets	**387**	164	**—**	—
Accounts payable and other	**(3)**	(3)	**(7)**	(7)
Other long-term liabilities	**(43)**	(132)	**(112)**	(150)
	341	29	**(119)**	(157)

1 Actuarial gains in 2022 and 2021 primarily due to increase in the discount rates used to measure the benefit obligations.
2 For pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. The accumulated benefit obligation for our pension plans was $1.8 billion and $2.2 billion as at December 31, 2022 and 2021, respectively.

Certain of our pension plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Accumulated benefit obligation	**42**	253
Fair value of plan assets	**—**	181

Certain of our pension plans have projected benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation and fair value of plan assets were as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Projected benefit obligation	**61**	895
Fair value of plan assets	**17**	760

AMOUNT RECOGNIZED IN ACCUMULATED OTHER COMPREHENSIVE INCOME

The amount of pre-tax AOCI relating to our OPEB plans are as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Net actuarial gain	**(51)**	(13)
Total amount recognized in AOCI	**(51)**	(13)

NET PERIODIC BENEFIT COST AND OTHER AMOUNTS RECOGNIZED IN COMPREHENSIVE INCOME

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Service cost	**60**	63	**2**	3
Interest cost[1]	**64**	51	**4**	4
Expected return on plan assets[1]	**(151)**	(131)	**—**	—
Amortization of net actuarial (gain)/loss[1,2]	**8**	28	**(1)**	—
Net periodic benefit (credit)/cost	**(19)**	11	**5**	7
Defined contribution benefit cost	**3**	2	**—**	—
Net pension and OPEB (credit)/cost recognized in Earnings	**(16)**	13	**5**	7
Amount recognized in OCI:				
Amortization of net actuarial gain	**—**	—	**1**	—
Net actuarial gain arising during the year	**—**	—	**(39)**	(31)
Total amount recognized in OCI	**—**	—	**(38)**	(31)
Total amount recognized in Comprehensive income	**(16)**	13	**(33)**	(24)

1 Reported within Other income in the Consolidated Statements of Earnings.
2 Reflects amortization of net actuarial loss arising from pension plans that are recognized as long-term regulatory assets (Note 5).

ACTUARIAL ASSUMPTIONS

The weighted average assumptions made in the measurement of the benefit obligation and net periodic benefit cost of our defined benefit pension and OPEB plans are as follows:

	Pension		OPEB	
	2022	2021	**2022**	2021
Benefit obligations				
Discount rate	**5.3%**	3.2%	**5.3%**	3.2%
Rate of salary increase	**2.8%**	2.9%	**3.0%**	3.0%
Net benefit cost				
Discount rate	**3.2%**	2.6%	**3.2%**	2.6%
Rate of return on plan assets	**6.3%**	6.0%	**N/A**	N/A
Rate of salary increase	**2.9%**	2.3%	**3.0%**	2.4%

ASSUMED HEALTH CARE COST TREND RATES

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	2022	2021
Health care cost trend rate assumed for next year	**4.0%**	4.0%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0%**	4.0%

PLAN ASSETS
We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

	Target	December 31,	
Asset Category	**Allocation**	**2022**	2021
Equity securities	**40.9%**	**36.9%**	44.9%
Fixed income securities	**34.1%**	**34.3%**	32.2%
Alternatives[1]	**25.0%**	**28.8%**	22.9%

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	2022				2021			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Cash and cash equivalents	**77**	**—**	**—**	**77**	42	—	—	42
Equity securities								
Canada	**—**	**191**	**—**	**191**	110	123	—	233
Global	**—**	**632**	**—**	**632**	—	853	—	853
Fixed income securities								
Government	**112**	**285**	**—**	**397**	141	294	—	435
Corporate	**—**	**289**	**—**	**289**	—	300	—	300
Alternatives[4]	**—**	**—**	**649**	**649**	—	—	552	552
Forward currency contracts	**—**	**(8)**	**—**	**(8)**	—	—	—	—
Total pension plan assets at fair value	**189**	**1,389**	**649**	**2,227**	293	1,570	552	2,415

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Balance at beginning of year	**552**	466
Unrealized and realized gains	**103**	49
Purchases and settlements, net	**(6)**	37
Balance at end of year	**649**	552

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2023	2024	2025	2026	2027	2028-2032
(millions of Canadian dollars)						
Pension	116	118	121	123	124	646
OPEB	7	7	7	7	7	38

EXPECTED EMPLOYER CONTRIBUTIONS

In 2023, we expect to contribute approximately $5 million and $7 million to the pension plans and OPEB plans, respectively.

17. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Accounts receivable and other	**(681)**	(14)
Accounts receivable from affiliates	**69**	(27)
Regulatory assets	**(597)**	(222)
Gas inventory	**(586)**	(242)
Deferred amounts and other assets	**(2)**	(2)
Accounts payable and other	**275**	196
Accounts payable to affiliates	**82**	(4)
Regulatory liabilities	**275**	(140)
Other long-term liabilities	**(6)**	(18)
	(1,171)	(473)

18. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. Affiliates refer to Enbridge and companies that are either directly or indirectly owned by Enbridge.

Enbridge and its affiliates perform centralized corporate functions for us pursuant to applicable agreements, including legal, accounting, compliance, treasury, employee benefits, information technology and other areas, as well as certain engineering and other services. We reimburse Enbridge for the expenses incurred to provide these services as well as for other expenses incurred on our behalf. In addition, we perform services and incur expenses on behalf of our affiliates, which are subsequently reimbursed. Our expenses and recoveries for these services are recorded in Operating and administrative expense in the Consolidated Statements of Earnings, and are based on the cost of actual services provided or using various allocation methodologies.

Our transactions with entities related through common or joint control and significantly influenced investees are as follows:

Years ended December 31,	2022	2021
(millions of Canadian dollars)		
Operating revenues[1]	57	85
Gas commodity and distribution costs[2, 3]	170	181
Operating and administrative expenses[4]	401	308

1 Includes wholesale gas procurement and transportation services provided to Gazifère Inc. of $43 million (2021 - $30 million), pursuant to a contract negotiated between us and approved by the OEB and Régie de l'énergie.
2 Includes the purchase of gas transportation services of $112 million (2021 - $111 million) from NEXUS Gas Transmission, LLC.
3 Includes the purchase of natural gas, storage, and transportation services of $30 million (2021 - $47 million) from Tidal Energy Marketing Inc. and Tidal Energy Marketing (U.S.) LLC.
4 Includes centralized corporate function transaction costs of $370 million (2021 - $280 million) from Enbridge and its affiliates.

Amounts due from/(to) related parties are as follows:

December 31,	2022	2021
(millions of Canadian dollars)		
Enbridge Inc.[1,2]	(345)	18
Enbridge Employee Services Canada Inc.	(49)	(61)
Enbridge Pipelines Inc.	33	35
Gazifère Inc.	13	25
Tidal Energy Marketing Inc.[3]	20	19
Other affiliates, net[4]	6	19
	(322)	55

1 Includes net qualifying interest cash flow hedges receivable and net derivative receivable balances from affiliate.
2 Balance includes Demand loan from affiliate.
3 Includes affiliate gas imbalance receivable. As at December 31, 2022 total affiliate gas imbalance receivable was $22 million (2021 - $23 million).
4 Includes current portion of operating lease liabilities to affiliates.

SHARE CAPITAL

During the year ended December 31, 2022, common share dividends declared on our Class A and Class B common shares were $56 million (2021 - $108 million) and $48 million (2021 - $92 million), respectively. During 2022, we also completed the return of capital transactions, and received capital contributions, as described in *Note 11 - Share Capital*.

CAPITALIZED SERVICE COSTS

We purchase gas meter services from Lakeside Performance Gas Services Ltd. (Lakeside), such as ongoing meter exchanges and inspections for customers in our franchise area. During the year ended December 31, 2022, we purchased gas meter services from Lakeside totaling $66 million, of which a portion of these costs was expensed to Operating and administrative expense and the remainder capitalized in Property, plant and equipment, net. We will continue purchasing these services at prevailing market prices under normal trade terms.

LEASES

We incur operating lease payments related to natural gas transportation and storage services from various affiliates. As at December 31, 2022 and 2021, affiliate right-of-use assets and lease liabilities were $43 million and $48 million, respectively. See *Note 14 - Leases* for further discussion.

AFFILIATE LOANS

December 31,	**2022**	2021
(millions of Canadian dollars)		
Enbridge Inc.[1]	**318**	—

1 During the year ended December 31, 2022, we borrowed $318 million on the demand loan. The demand loan bears an interest rate of the Canadian Dollar Offered Rate plus a margin of 100 basis points.

See *Note 10 - Debt* for total interest on our loan from affiliate.

19. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2022, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	9,745	350	300	745	650	350	7,350
Purchase of services, pipe and other materials, including transportation[2]	5,935	2,367	675	510	465	361	1,557
Right-of-way commitments	739	13	13	13	13	13	674
Total	16,419	2,730	988	1,268	1,128	724	9,581

1 Includes debentures and term notes, and excludes short-term borrowings, debt discounts, debt issuance costs, finance lease obligations and the fair value adjustment from push-down accounting. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements. Therefore, the actual timing of future cash repayments could be materially different than presented above.

2 Includes capital and operating commitments. Consists primarily of firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; and customer care services.

ENVIRONMENTAL

We are subject to various Canadian federal, provincial and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to natural gas pipeline operations, and we and our affiliates are, at times, subject to environmental remediation obligations at various sites where we operate. We manage this environmental risk through appropriate environmental policies, programs and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of costs arising from environmental incidents associated with our operating activities.

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. We were named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by us for the operation of our MGP.

While these Statements of Claim were filed by the City and the School Board, they were never formally served on us. It was and remains our understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, we entered into an agreement with the City (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with us. To our knowledge, neither the City nor the School Board has taken any steps to advance the lawsuits.

Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time, as there are a number of potential alternative remediation, isolation and containment approaches which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the US for the recovery in rates of costs relating to the remediation of former MGP sites. From 2006 to 2018, the OEB approved the establishment of deferral accounts to record the costs of investigating, defending and dealing with ongoing MGP-related claims. We expect that if it is found that we must contribute to any remediation costs, either as a result of a lawsuit or government order, we may be generally allowed to recover in rates those substantial costs not recovered through insurance or by other means. Accordingly, we believe that the ultimate outcome of these matters will not have a significant impact on our financial position.

Hamilton Contaminated Site

In April 2016, the Ontario Ministry of the Environment, Conservation and Parks (MECP), formerly the Ministry of the Environment and Climate Change, issued a Director's Order (the Order) naming us, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of ours in Hamilton. In May 2016, we appealed the Order, and in June 2016, the Environmental Review Tribunal (the Tribunal), on consent of the MECP's Director, stayed the application of parts of the Order. The Tribunal extended the stay of the Order several times, which allowed the owner of the property, with the cooperation of the adjacent owners, to prepare a plan of action, including discussions with the MECP and other neighbors. On February 4, 2021, the MECP determined that we and other parties have complied with the Order and no further obligations are outstanding. Accordingly, we withdrew our appeal, and the Tribunal has accepted the withdrawal and has closed its file.

OTHER LITIGATION

We are subject to various legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS

We maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

20. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2022, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, page 8 and Schedule 2
EB-2021-0149 Exhibit I.FRPO.20 & .21 and Decision on Settlement Proposal, Schedule 1, Settlement Proposal, page 16

Preamble:

In the first reference, EGI evidence states: “The C1 Short-Term Firm Peak Storage revenues of $1.536 million were $6.347million lower than the 2013 Board-approved forecast of $7.883 million. Actual Union rate zone utility storage requirements for 2021 were 8.3 PJ higher than the 2013 OEB-approved forecast, resulting in a decrease in the C1 Short-Term Firm Peak Storage available for sale (from 11.3 PJ in 2013 OEB-approved to 3.0 PJ in 2021). Union rate zone customers received the value of storage directly through the use of the storage space, rather than through the sale of short-term storage.

We would like to understand better the determination of storage needs to in-franchise customers in the Union Gas rate zones and the ST Storage Deferral Account. We are asking again for a description of the determination and the data used for that determination. To be clear, stating that the numbers are for the Winter of 2022/23 or the 2022 Gas Supply plan is not helpful.

In the second reference, the Board-approved settlement agreement stated: In connection with the settlement of this issue, Enbridge Gas agrees that in future deferral and variance account clearance applications during the deferred rebasing term it will include evidence about the determination of storage space and deliverability by rate class.

Question(s):

For the winters used to determine the needs used in this application, please provide a description of the process, the figures used and derivation of the amount of the following in tabular form with accompanying Excel spreadsheets (filed with the Board) for:

a) the determination of the storage space.
b) a specific reference to allocation factors to allocate space to each respective rate class.

c) the determination of the amount of deliverability required by each general service rate class.

Response:

a) The storage space forecast is based on the needs for sales service and bundled customers calculated using the aggregate excess methodology at a rate zone level. Storage space needs for semi-unbundled and Union North T-service customers is forecast based on the contracted or reserved storage space needs by the customer. Aggregate excess is calculated as the total winter demand (the 151 days of winter from November 1 to March 31) less the total average demands multiplied by 151.

Table 1 provides the derivation of total 2022 storage space.

Table 1

2022 Storage Space

Line No.	Particulars (PJ)	Rate Zone EGD	Rate Zone Union North	Rate Zone Union South	Total
	Aggregate Excess				
1	Winter Demand	319.0	40.2	149.3	508.5
2	Annual Demand	467.4	58.5	225.5	751.4
3	Aggregate Excess (1)	125.6	16.0	56.0	197.7
4	Customer Contracted/ Reserved Storage Space	-	1.0	14.0	14.9
5	Total	125.6	17.0	70.0	212.6
6	Excess Utility Storage Space				3.5
7	System Integrity Storage Space				9.5
8	Total Storage Space				225.6

Notes:
(1) Aggregate excess calculated as Line 1 - (Line 2 x 151/365).

b) The allocation of storage space to rate classes, including general service rate classes, is not prepared on an annual basis. For purposes of providing the rate class level detail at Exhibit E, Tab 1, Schedule 2, Appendix A, Enbridge Gas used the most recently available rate class allocation of storage space from the 2018 cost allocation study[1] for the EGD rate zone and from the 2019 cost allocation study filed by Union Gas in its 2020 Rates[2] application for the Union rate zones. The storage space allocation within each cost allocation study used the aggregate excess methodology as described above but at the individual rate class level.

c) For the EGD rate zone, the storage deliverability forecast is based on the cost-based storage deliverability of Tecumseh and Crowland storage plus the storage deliverability provided through market-based storage contracts.

For the Union rate zones, the storage deliverability forecast is calculated as the excess of sales service, bundled and semi-unbundled customer design day demand over design day deliveries.

Table 2 provides the derivation of total 2022 storage deliverability.

Table 2

2022 Storage Deliverability

Line No.	Particulars (GJ/d)	Rate Zone EGD (1)	 Union North	 Union South	Total
1	Design Day Demands		466,491	3,270,312	
2	Design Day Deliveries		(156,897)	(1,513,851)	
3	Total	2,193,125	309,594	1,756,462	4,259,181
4	Excess Utility Storage Space Deliverability (2)				41,795
5	Total Deliverability (3)				4,300,976

Notes:
(1) EGD total storage deliverability calculated as 1,920,948 GJ/d of cost-based storage deliverability plus 272,177 GJ/d of market-based storage deliverability.
(2) Calculated as 1.2% of excess utility storage space.
(3) The in-franchise storage deliverability in Table 2 reflects the utilization by Regulated customers but does not reflect allocated costs affirmed in EB-2011-0038.

[1] EB-2017-0086.
[2] EB-2019-0194.

The allocation of deliverability to rate classes, including general service rate classes, is not prepared on an annual basis. For purposes of providing the rate class level detail at Exhibit E, Tab 1, Schedule 2, Appendix A, Enbridge Gas used the most recently available rate class allocation of storage deliverability from the 2018 cost allocation study[3] for the EGD rate zone and from the 2019 cost allocation study filed by Union Gas in its 2020 Rates[4] application for the Union rate zones. The storage deliverability allocation to EGD rate classes was based on the rate class contribution of the excess of peak day requirements over average winter demand and the allocation to Union Gas rate classes was based on the excess of design day demand over design day deliveries at the individual rate class level.

[3] EB-2017-0086.
[4] EB-2019-0194.

Table 1
2022 Storage Space

Line No.	Particulars (PJ)	Rate Zone EGD	Union North	Union South	Total
	Aggregate Excess				
1	Winter Demand	319.0	40.2	149.3	508.5
2	Annual Demand	467.4	58.5	225.5	751.4
3	Aggregate Excess (1)	125.6	16.0	56.0	197.7
	Customer Contracted/				
4	Reserved Storage Space	-	1.0	14.0	14.9
5	Total	125.6	17.0	70.0	212.6
6	Excess Utility Storage Space				3.5
7	System Integrity Storage Space				9.5
8	Total Storage Space				225.6

Notes:
(1) Aggregate excess calculated as Line 1 - (Line 2 x 151/365).

Table 2
2022 Storage Deliverability

Line No.	Particulars (GJ/d)	Rate Zone: EGD (1)	Rate Zone: Union North	Rate Zone: Union South	Total
1	Design Day Demands		466,491	3,270,312	
2	Design Day Deliveries		(156,897)	(1,513,851)	
3	Total	2,193,125	309,594	1,756,462	4,259,181
4	Excess Utility Storage Space Deliverability (2)				41,795
5	Total Deliverability (3)				4,300,976

Notes:
(1) EGD total storage deliverability calculated as 1,920,948 GJ/d of cost-based storage deliverability plus 272,177 GJ/d of market-based storage deliverability.
(2) Calculated as 1.2% of excess utility storage space.
(3) The in-franchise storage deliverability in Table 2 reflects the utilization by Regulated customers but does not reflect allocated costs affirmed in EB-2011-0038.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 3, Page 1 and
EB-2022-0110 Exhibit I.FRPO.13

Preamble:

The first reference provides a table entitled SUMMARY OF NON-UTILITY STORAGE BALANCES - UNION RATE ZONES that depicts an entitlement of 129.3PJ with daily balances.

The second reference response included: As posted on the Enbridge Gas website under operational information/storage reporting, the working capacity of Legacy Union Gas is 183.7 PJ of which 100 PJ is utility (as per NGEIR). The working capacity of Legacy Enbridge Gas is 122.9 PJ of which 99.4 PJ is utility (as per NGEIR).
We would like to understand the evidence provided and the actual balances in relation to the encroachment directives of the Board.

Question(s):

Please confirm or correct the title of the slide that specifies “Union Rate Zones”.

a) For the 127.6 PJ, please provide the sources of non-utility space between:
    i) Legacy Union Gas
    ii) Legacy Enbridge Gas
    iii) Other sources

(1) Please describe the other sources (i.e., other Ontario storage, other Michigan storage, etc.)

Response:

The title of the slide should be “Summary of Non-Utility Storage Balances”.

a) The total available working capacity is updated in Exhibit I.FRPO.12 Attachment 1.

The total Non-Utility Storage Balance is 129.3 PJ which is comprised of:

i) Legacy Union Gas is 86.7 PJ (equal to 186.7 PJ total less the 100 PJ of regulated storage)
ii) Legacy EGD is 27.9 PJ (equal to 127.6 PJ less the 99.7 PJ of regulated storage)
iii) Other sources account for the remaining 14.7 PJ of the storage space, made up of market based services.

1. Unregulated storage is not relevant in the context of this proceeding. As noted already, Enbridge Gas does not make use of any regulated storage space for non-utility space. Enbridge Gas does not feel it is relevant to detail the other sources of unregulated storage.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 3, Page 1 and
EB-2022-0110 Exhibit I.FRPO.13

Preamble:

The first reference provides a table entitled SUMMARY OF NON-UTILITY STORAGE BALANCES - UNION RATE ZONES that depicts an entitlement of 129.3PJ with daily balances.

The second reference response included: As posted on the Enbridge Gas website under operational information/storage reporting, the working capacity of Legacy Union Gas is 183.7 PJ of which 100 PJ is utility (as per NGEIR). The working capacity of Legacy Enbridge Gas is 122.9 PJ of which 99.4 PJ is utility (as per NGEIR).
We would like to understand the evidence provided and the actual balances in relation to the encroachment directives of the Board.

Question(s):

Please update the storage space numbers and specify the source (project, purchase, etc.) of the incremental space for each legacy utility.

Response:

Please see Attachment 1 to this response as well as the response to Exhibit I.FRPO.11.

ENBRIDGE GAS INC.
Continuity of Storage Space Working Capacity

Line No.	Particulars (PJ)	Working Capacity Oct-20	2020/21 Storage Enhancement Project (1)	2022 Storage Enhancement Project (2)	Storage Pool Adjustments	Current Working Capacity
1	UGL	183.7		2.0	0.9	186.7
2	EGD	122.9	3.4	1.4	(0.2)	127.6
3	Total	306.6	3.4	3.5	0.7	314.3

Notes: (1) EB-2020-0256 Storage Enhancement (Ladysmith, Sekerton and Corunna)
(2) EB-2021-0078 Storage Enhancement (Payne, Dow Moore)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 3, Page 1 and
EB-2022-0110 Exhibit I.FRPO.13

Preamble:

The first reference provides a table entitled SUMMARY OF NON-UTILITY STORAGE BALANCES - UNION RATE ZONES that depicts an entitlement of 129.3PJ with daily balances.

The second reference response included: As posted on the Enbridge Gas website under operational information/storage reporting, the working capacity of Legacy Union Gas is 183.7 PJ of which 100 PJ is utility (as per NGEIR). The working capacity of Legacy Enbridge Gas is 122.9 PJ of which 99.4 PJ is utility (as per NGEIR).

We would like to understand the evidence provided and the actual balances in relation to the encroachment directives of the Board.

Question(s):

Please provide a table for each of last three years for UGL and EGD's non-utility storage space and daily values of actual balances for October and November separately.

Response:

Please see Attachment 1.

TABLE 1
SUMMARY OF NON-UTILITY STORAGE BALANCES

Line No.	Col. 1 Date	Col. 2 Entitlement (PJ)	Col. 3 Balance (PJ)	Col. 4 % Full (%)	Line No.	Col. 5 Date	Col. 6 Entitlement (PJ)	Col. 7 Balance (PJ)	Col. 8 % Full (%)
1.	1-Oct-19	113.9	110.0	97%	32.	1-Nov-19	113.9	110.3	97%
2.	2-Oct-19	113.9	109.9	96%	33.	2-Nov-19	113.9	110.6	97%
3.	3-Oct-19	113.9	109.7	96%	34.	3-Nov-19	113.9	110.7	97%
4.	4-Oct-19	113.9	110.0	97%	35.	4-Nov-19	113.9	111.0	97%
5.	5-Oct-19	113.9	110.1	97%	36.	5-Nov-19	113.9	111.1	98%
6.	6-Oct-19	113.9	110.3	97%	37.	6-Nov-19	113.9	111.4	98%
7.	7-Oct-19	113.9	110.5	97%	38.	7-Nov-19	113.9	111.2	98%
8.	8-Oct-19	113.9	110.6	97%	39.	8-Nov-19	113.9	111.0	97%
9.	9-Oct-19	113.9	110.7	97%	40.	9-Nov-19	113.9	110.8	97%
10.	10-Oct-19	113.9	110.8	97%	41.	10-Nov-19	113.9	110.5	97%
11.	11-Oct-19	113.9	110.9	97%	42.	11-Nov-19	113.9	109.9	96%
12.	12-Oct-19	113.9	110.9	97%	43.	12-Nov-19	113.9	108.3	95%
13.	13-Oct-19	113.9	110.9	97%	44.	13-Nov-19	113.9	107.4	94%
14.	14-Oct-19	113.9	110.9	97%	45.	14-Nov-19	113.9	106.8	94%
15.	15-Oct-19	113.9	110.8	97%	46.	15-Nov-19	113.9	106.5	93%
16.	16-Oct-19	113.9	110.6	97%	47.	16-Nov-19	113.9	106.2	93%
17.	17-Oct-19	113.9	110.4	97%	48.	17-Nov-19	113.9	106.0	93%
18.	18-Oct-19	113.9	110.3	97%	49.	18-Nov-19	113.9	105.5	93%
19.	19-Oct-19	113.9	110.3	97%	50.	19-Nov-19	113.9	105.3	92%
20.	20-Oct-19	113.9	110.4	97%	51.	20-Nov-19	113.9	105.1	92%
21.	21-Oct-19	113.9	110.5	97%	52.	21-Nov-19	113.9	105.3	92%
22.	22-Oct-19	113.9	110.7	97%	53.	22-Nov-19	113.9	105.8	93%
23.	23-Oct-19	113.9	110.8	97%	54.	23-Nov-19	113.9	105.9	93%
24.	24-Oct-19	113.9	110.9	97%	55.	24-Nov-19	113.9	106.1	93%
25.	25-Oct-19	113.9	110.9	97%	56.	25-Nov-19	113.9	106.4	93%
26.	26-Oct-19	113.9	110.9	97%	57.	26-Nov-19	113.9	107.2	94%
27.	27-Oct-19	113.9	111.0	97%	58.	27-Nov-19	113.9	107.4	94%
28.	28-Oct-19	113.9	109.8	96%	59.	28-Nov-19	113.9	107.5	94%
29.	29-Oct-19	113.9	109.9	97%	60.	29-Nov-19	113.9	107.2	94%
30.	30-Oct-19	113.9	110.0	97%	61.	30-Nov-19	113.9	107.0	94%
31.	31-Oct-19	113.9	110.1	97%					

TABLE 2
SUMMARY OF NON-UTILITY STORAGE BALANCES

	Col. 1	Col. 2	Col. 3	Col. 4		Col. 5	Col. 6	Col. 7	Col. 8
Line No.	Date	Entitlement	Balance	% Full	Line No.	Date	Entitlement	Balance	% Full
		(PJ)	(PJ)	(%)			(PJ)	(PJ)	(%)
1	1-Oct-20	122.2	121.6	99.5%	32	1-Nov-20	122.2	117.6	96.3%
2	2-Oct-20	122.2	121.5	99.4%	33	2-Nov-20	122.2	116.7	95.5%
3	3-Oct-20	122.2	121.4	99.3%	34	3-Nov-20	122.2	116.4	95.2%
4	4-Oct-20	122.2	121.2	99.1%	35	4-Nov-20	122.2	116.8	95.6%
5	5-Oct-20	122.2	120.9	98.9%	36	5-Nov-20	122.2	117.4	96.1%
6	6-Oct-20	122.2	120.3	98.5%	37	6-Nov-20	122.2	118.4	96.9%
7	7-Oct-20	122.2	120.4	98.6%	38	7-Nov-20	122.2	118.8	97.2%
8	8-Oct-20	122.2	120.3	98.4%	39	8-Nov-20	122.2	119.1	97.4%
9	9-Oct-20	122.2	120.7	98.7%	40	9-Nov-20	122.2	119.4	97.7%
10	10-Oct-20	122.2	120.8	98.9%	41	10-Nov-20	122.2	119.6	97.9%
11	11-Oct-20	122.2	120.9	98.9%	42	11-Nov-20	122.2	119.6	97.9%
12	12-Oct-20	122.2	121.0	99.0%	43	12-Nov-20	122.2	119.4	97.7%
13	13-Oct-20	122.2	120.9	99.0%	44	13-Nov-20	122.2	119.4	97.7%
14	14-Oct-20	122.2	121.0	99.0%	45	14-Nov-20	122.2	119.4	97.7%
15	15-Oct-20	122.2	120.9	99.0%	46	15-Nov-20	122.2	119.4	97.7%
16	16-Oct-20	122.2	120.9	98.9%	47	16-Nov-20	122.2	119.3	97.6%
17	17-Oct-20	122.2	121.0	99.0%	48	17-Nov-20	122.2	118.8	97.2%
18	18-Oct-20	122.2	121.1	99.1%	49	18-Nov-20	122.2	118.2	96.7%
19	19-Oct-20	122.2	121.0	99.0%	50	19-Nov-20	122.2	118.1	96.7%
20	20-Oct-20	122.2	121.3	99.3%	51	20-Nov-20	122.2	118.3	96.8%
21	21-Oct-20	122.2	121.3	99.2%	52	21-Nov-20	122.2	118.3	96.8%
22	22-Oct-20	122.2	121.4	99.3%	53	22-Nov-20	122.2	118.3	96.8%
23	23-Oct-20	122.2	121.7	99.6%	54	23-Nov-20	122.2	117.9	96.5%
24	24-Oct-20	122.2	121.8	99.6%	55	24-Nov-20	122.2	117.5	96.1%
25	25-Oct-20	122.2	121.8	99.7%	56	25-Nov-20	122.2	117.4	96.1%
26	26-Oct-20	122.2	121.5	99.4%	57	26-Nov-20	122.2	117.3	95.9%
27	27-Oct-20	122.2	120.5	98.6%	58	27-Nov-20	122.2	117.2	95.9%
28	28-Oct-20	122.2	119.8	98.1%	59	28-Nov-20	122.2	117.2	95.9%
29	29-Oct-20	122.2	118.9	97.3%	60	29-Nov-20	122.2	117.2	95.9%
30	30-Oct-20	122.2	118.3	96.8%	61	30-Nov-20	122.2	117.0	95.8%
31	31-Oct-20	122.2	118.0	96.6%					

TABLE 3
SUMMARY OF NON-UTILITY STORAGE BALANCES

Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Line No.	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1-Oct-21	127.6	118.8	93.1%	32	1-Nov-21	127.6	121.4	95.1%
2-Oct-21	127.6	119.0	93.2%	33	2-Nov-21	127.6	121.4	95.2%
3-Oct-21	127.6	118.9	93.2%	34	3-Nov-21	127.6	121.2	95.0%
4-Oct-21	127.6	118.6	93.0%	35	4-Nov-21	127.6	121.2	95.0%
5-Oct-21	127.6	118.5	92.9%	36	5-Nov-21	127.6	121.4	95.2%
6-Oct-21	127.6	118.6	93.0%	37	6-Nov-21	127.6	121.6	95.3%
7-Oct-21	127.6	118.7	93.0%	38	7-Nov-21	127.6	121.8	95.4%
8-Oct-21	127.6	118.7	93.0%	39	8-Nov-21	127.6	121.7	95.4%
9-Oct-21	127.6	118.9	93.2%	40	9-Nov-21	127.6	122.2	95.8%
10-Oct-21	127.6	119.0	93.3%	41	10-Nov-21	127.6	122.9	96.3%
11-Oct-21	127.6	119.2	93.4%	42	11-Nov-21	127.6	123.8	97.0%
12-Oct-21	127.6	119.2	93.4%	43	12-Nov-21	127.6	124.5	97.6%
13-Oct-21	127.6	119.3	93.5%	44	13-Nov-21	127.6	125.1	98.1%
14-Oct-21	127.6	119.3	93.5%	45	14-Nov-21	127.6	125.2	98.1%
15-Oct-21	127.6	119.4	93.6%	46	15-Nov-21	127.6	125.2	98.1%
16-Oct-21	127.6	119.6	93.8%	47	16-Nov-21	127.6	125.4	98.3%
17-Oct-21	127.6	119.7	93.9%	48	17-Nov-21	127.6	125.9	98.7%
18-Oct-21	127.6	119.7	93.9%	49	18-Nov-21	127.6	126.1	98.9%
19-Oct-21	127.6	119.7	93.8%	50	19-Nov-21	127.6	125.9	98.7%
20-Oct-21	127.6	119.7	93.9%	51	20-Nov-21	127.6	125.9	98.7%
21-Oct-21	127.6	119.8	93.9%	52	21-Nov-21	127.6	125.9	98.7%
22-Oct-21	127.6	119.8	93.9%	53	22-Nov-21	127.6	125.1	98.1%
23-Oct-21	127.6	119.9	94.0%	54	23-Nov-21	127.6	124.3	97.4%
24-Oct-21	127.6	120.1	94.1%	55	24-Nov-21	127.6	124.1	97.3%
25-Oct-21	127.6	120.1	94.1%	56	25-Nov-21	127.6	124.0	97.2%
26-Oct-21	127.6	120.2	94.2%	57	26-Nov-21	127.6	123.9	97.1%
27-Oct-21	127.6	120.3	94.3%	58	27-Nov-21	127.6	123.5	96.8%
28-Oct-21	127.6	120.6	94.5%	59	28-Nov-21	127.6	122.9	96.3%
29-Oct-21	127.6	120.9	94.8%	60	29-Nov-21	127.6	122.2	95.8%
30-Oct-21	127.6	121.1	94.9%	61	30-Nov-21	127.6	121.7	95.4%
31-Oct-21	127.6	121.3	95.1%					

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 3, Page 1 and
EB-2022-0110 Exhibit I.FRPO.13

Preamble:

The first reference provides a table entitled SUMMARY OF NON-UTILITY STORAGE BALANCES - UNION RATE ZONES that depicts an entitlement of 129.3PJ with daily balances.

The second reference response included: As posted on the Enbridge Gas website under operational information/storage reporting, the working capacity of Legacy Union Gas is 183.7 PJ of which 100 PJ is utility (as per NGEIR). The working capacity of Legacy Enbridge Gas is 122.9 PJ of which 99.4 PJ is utility (as per NGEIR).

We would like to understand the evidence provided and the actual balances in relation to the encroachment directives of the Board.

Question(s):

Please provide comparable tables for the utility storage for each legacy storage system.

Response:

Please see Attachment 1, for Union Gas and Enbridge Gas Distribution system inventory balances for October and November 2022.

Table 1
UNION GAS
Summary of Utility Storage Balances

Line No.	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1	1-Oct-22	100.0	77.6	77.6%	1-Nov-22	100.0	87.3	87.3%
2	2-Oct-22	100.0	77.7	77.7%	2-Nov-22	100.0	88.0	88.0%
3	3-Oct-22	100.0	77.3	77.3%	3-Nov-22	100.0	88.3	88.3%
4	4-Oct-22	100.0	77.0	77.0%	4-Nov-22	100.0	89.0	89.0%
5	5-Oct-22	100.0	77.1	77.1%	5-Nov-22	100.0	89.9	89.9%
6	6-Oct-22	100.0	77.7	77.7%	6-Nov-22	100.0	90.6	90.6%
7	7-Oct-22	100.0	79.4	79.4%	7-Nov-22	100.0	90.7	90.7%
8	8-Oct-22	100.0	79.3	79.3%	8-Nov-22	100.0	90.4	90.4%
9	9-Oct-22	100.0	83.4	83.4%	9-Nov-22	100.0	90.4	90.4%
10	10-Oct-22	100.0	83.3	83.3%	10-Nov-22	100.0	91.0	91.0%
11	11-Oct-22	100.0	83.2	83.2%	11-Nov-22	100.0	91.4	91.4%
12	12-Oct-22	100.0	83.4	83.4%	12-Nov-22	100.0	91.0	91.0%
13	13-Oct-22	100.0	83.4	83.4%	13-Nov-22	100.0	90.1	90.1%
14	14-Oct-22	100.0	83.8	83.8%	14-Nov-22	100.0	88.9	88.9%
15	15-Oct-22	100.0	83.8	83.8%	15-Nov-22	100.0	87.3	87.3%
16	16-Oct-22	100.0	84.1	84.1%	16-Nov-22	100.0	85.8	85.8%
17	17-Oct-22	100.0	83.9	83.9%	17-Nov-22	100.0	84.2	84.2%
18	18-Oct-22	100.0	83.4	83.4%	18-Nov-22	100.0	82.7	82.7%
19	19-Oct-22	100.0	83.0	83.0%	19-Nov-22	100.0	81.3	81.3%
20	20-Oct-22	100.0	82.6	82.6%	20-Nov-22	100.0	79.6	79.6%
21	21-Oct-22	100.0	83.3	83.3%	21-Nov-22	100.0	78.3	78.3%
22	22-Oct-22	100.0	84.3	84.3%	22-Nov-22	100.0	77.5	77.5%
23	23-Oct-22	100.0	85.2	85.2%	23-Nov-22	100.0	77.1	77.1%
24	24-Oct-22	100.0	86.0	86.0%	24-Nov-22	100.0	77.1	77.1%
25	25-Oct-22	100.0	86.6	86.6%	25-Nov-22	100.0	77.1	77.1%
26	26-Oct-22	100.0	87.1	87.1%	26-Nov-22	100.0	77.5	77.5%
27	27-Oct-22	100.0	86.9	86.9%	27-Nov-22	100.0	77.8	77.8%
28	28-Oct-22	100.0	86.5	86.5%	28-Nov-22	100.0	77.2	77.2%
29	29-Oct-22	100.0	86.7	86.7%	29-Nov-22	100.0	76.6	76.6%
30	30-Oct-22	100.0	86.8	86.8%	30-Nov-22	100.0	75.6	75.6%
31	31-Oct-22	100.0	87.4	87.4%				

Table 2
ENBRIDGE GAS DISTRIBUTION
Summary of Utility Storage Balances

Line No.	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1	1-Oct-22	99.4	96.1	96.7%	1-Nov-22	99.4	95.9	96.5%
2	2-Oct-22	99.4	96.6	97.2%	2-Nov-22	99.4	95.9	96.5%
3	3-Oct-22	99.4	97.3	97.9%	3-Nov-22	99.4	95.9	96.5%
4	4-Oct-22	99.4	98.1	98.7%	4-Nov-22	99.4	95.9	96.5%
5	5-Oct-22	99.4	98.6	99.3%	5-Nov-22	99.4	95.9	96.5%
6	6-Oct-22	99.4	99.0	99.6%	6-Nov-22	99.4	95.9	96.5%
7	7-Oct-22	99.4	97.4	98.0%	7-Nov-22	99.4	95.9	96.5%
8	8-Oct-22	99.4	97.7	98.3%	8-Nov-22	99.4	95.9	96.5%
9	9-Oct-22	99.4	94.1	94.7%	9-Nov-22	99.4	95.9	96.5%
10	10-Oct-22	99.4	94.4	95.0%	10-Nov-22	99.4	95.9	96.5%
11	11-Oct-22	99.4	95.0	95.6%	11-Nov-22	99.4	95.9	96.5%
12	12-Oct-22	99.4	95.3	95.9%	12-Nov-22	99.4	95.9	96.5%
13	13-Oct-22	99.4	95.6	96.2%	13-Nov-22	99.4	95.9	96.5%
14	14-Oct-22	99.4	95.8	96.5%	14-Nov-22	99.4	95.9	96.5%
15	15-Oct-22	99.4	96.1	96.7%	15-Nov-22	99.4	95.9	96.5%
16	16-Oct-22	99.4	96.3	96.9%	16-Nov-22	99.4	95.9	96.5%
17	17-Oct-22	99.4	96.3	96.9%	17-Nov-22	99.4	95.9	96.5%
18	18-Oct-22	99.4	96.3	96.9%	18-Nov-22	99.4	95.9	96.5%
19	19-Oct-22	99.4	96.4	97.0%	19-Nov-22	99.4	95.9	96.5%
20	20-Oct-22	99.4	96.4	97.0%	20-Nov-22	99.4	95.9	96.5%
21	21-Oct-22	99.4	96.4	97.0%	21-Nov-22	99.4	95.9	96.5%
22	22-Oct-22	99.4	96.5	97.1%	22-Nov-22	99.4	95.9	96.5%
23	23-Oct-22	99.4	96.6	97.2%	23-Nov-22	99.4	95.9	96.5%
24	24-Oct-22	99.4	96.7	97.3%	24-Nov-22	99.4	95.9	96.5%
25	25-Oct-22	99.4	96.7	97.3%	25-Nov-22	99.4	95.9	96.5%
26	26-Oct-22	99.4	96.7	97.3%	26-Nov-22	99.4	95.9	96.5%
27	27-Oct-22	99.4	96.6	97.2%	27-Nov-22	99.4	95.9	96.5%
28	28-Oct-22	99.4	96.5	97.1%	28-Nov-22	99.4	95.9	96.5%
29	29-Oct-22	99.4	96.4	97.0%	29-Nov-22	99.4	95.9	96.5%
30	30-Oct-22	99.4	96.2	96.8%	30-Nov-22	99.4	95.9	96.5%
31	31-Oct-22	99.4	95.9	96.5%				

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, including Table 3 and Schedule 3

Preamble:

EGI evidence states: In the EGD Rate Zone, actual UAF was determined to be 256,332 10^3m^3. The forecast UAF volume of UAF was 106,677 10^3m^3. The variance between actual and forecasted UAF volumes of 149,656 10^3m^3, resulted in a debit balance of $41.4 million in the UAFVA, plus interest. Exhibit D, Tab 1, Schedule 3 provides the detailed calculations of the UAFVA balance.

We would like to understand the derivation of the debit balance, the process for replacing and the ratepayer impacts.

Question(s):

Please describe fully the method of determination "Actual UFG Volumes" in Table 3. Please ensure the description includes the application of monthly heat values for both Sendout and Consumption and also how area measurement is applied

Response:

Please see response at Exhibit I.FRPO.16.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, including Table 3 and Schedule 3

Preamble:

EGI evidence states: In the EGD Rate Zone, actual UAF was determined to be 256,332 103m3. The forecast UAF volume of UAF was 106,677 103m3. The variance between actual and forecasted UAF volumes of 149,656 103m3, resulted in a debit balance of $41.4 million in the UAFVA, plus interest. Exhibit D, Tab 1, Schedule 3 provides the detailed calculations of the UAFVA balance.
We would like to understand the derivation of the debit balance, the process for replacing and the ratepayer impacts.

Question(s):

Please reconcile and describe the difference between the Actual UFG volumes shown in line 12 of Table 3 and the Total Actual UAF shown in line 6 of Schedule 3.

a) Please ensure the description address heat value (estimated vs. actual) in the respective determinations for each table.

b) Please produce monthly tables that show the determination of the monthly values for Sendout, estimates of Billed and Unbilled Volumes, and subsequent true-up for estimated to actual volumes and heat values. Please ensure to provide a description of the source of the information.

c) Please provide the specific reference to the Board-approval of this approach to the determination of UAFVA recovery.

Response:

There is no difference between the Actual UFG volumes shown in line 12 of Table 3 and the Total Actual UAF shown in line 6 of Schedule 3. The volume reported in both tables is 256,333 10^3m^3.

a) - b)

Please see Attachment 1 for the calculation of the actual UAF volumes, including monthly values for Sendout, Billed Consumption, Unbilled/Nobilled Estimated Consumption and True-ups, and Heat Value Adjustments.

c) The UAFVA accounting order and accounting principles underlying the calculation of recorded balances were established in 2002 and most recently approved by the OEB in the Company's 2020 Rates proceeding (EB-2019-0194). The OEB-approved UAFVA accounting order is included as Attachment 2.

The UAFVA accounting order directs that Enbridge Gas record differences between the estimated UAF and actual UAF, as well as allocate UAF annual variance on a monthly basis in proportion to actual sales and costed at the monthly PGVA reference price. Enbridge Gas has consistently applied this methodology to determine UAFVA balances. More broadly, the calculation methodologies applied for the purposes of calculating 2022 UAFVA balance is consistent with those used to calculate historic balances that were previously approved by the OEB (most recently in EB-2022-0110).

Calculation of 2022 UAF Volumes for the EGD Rate Zone

Line No.	Particulars (10^3m^3)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Sendout (1)	2,248,275	1,810,630	1,575,685	1,051,203	538,960	401,652	380,753	364,848	380,151	782,339	1,173,433	1,678,836	12,386,766
2	Billed Consumption (2)	1,856,799	1,951,713	1,773,427	1,306,217	891,270	330,657	438,243	424,603	327,048	536,516	891,596	1,286,801	12,014,890
3	Unbilled/Nobill Estimated Consumption (3)	1,173,309	1,093,576	756,725	570,720	229,364	297,827	214,835	143,679	239,883	430,516	713,518	958,153	6,822,104
4	Unbilled/Nobill Estimate Reversal (3)	(886,112)	(1,173,309)	(1,093,576)	(756,725)	(570,720)	(229,364)	(297,827)	(214,835)	(143,679)	(239,883)	(430,516)	(713,518)	(6,750,062)
5	Estimation True-up for Prior Year (4)	28,218	0	0	0	0	0	(0)	0	(0)	0	0	15,283	43,501
6	Total Consumption	2,172,214	1,871,981	1,436,576	1,120,212	549,914	399,120	355,250	353,447	423,253	727,149	1,174,597	1,546,720	12,130,433
7	EGD UAF Volume (5)	76,061	(61,350)	139,110	(69,010)	(10,953)	2,531	25,502	11,401	(43,101)	55,190	(1,164)	132,116	256,333
8	Annual Heat Value (6)	39.32	39.32	39.32	39.12	39.12	39.12	39.12	39.12	39.12	39.12	39.12	39.12	
9	Actual Heat Value (7)	39.15	39.12	39.09	38.93	38.66	38.56	38.59	38.76	38.75	38.76	38.94	39.08	
10	Heat Value Adjustment (8)	(9,450)	(9,434)	(8,448)	(5,447)	(6,481)	(5,803)	(4,870)	(3,263)	(4,011)	(6,808)	(5,444)	(1,449)	

Notes:
(1) Please see response at Exhibit I.EP.9. Sendout is converted to volumes based on the actual heat value shown on line 9.
(2) Billed consumption is sourced from the SAP CIS billing system
(3) Unbilled/Nobill Estimated Consumption is a monthly calculation prepared by Enbridge Gas. Please see Exhibit D, Tab 1 page 14-19 for description
(4) Estimation True-up for Prior Year is an annual calculation prepared by Enbridge Gas. See Exhibit D, Tab 1, Page 18-19
(5) Line 7 = Line 1 - Line 6. Refer to Exhibit D, Tab 1, Table 3, Line 12.
(6) Please see response at Exhibit I.EP.7 for description of annual heat value calculation
(7) Please see response at Exhibit I.EP.7. Actual heat value is determined by taking the actual monthly sendout quantity in units of energy (GJ) divided by the actual sendout quantity in units of volumes (10^3m^3). Actual sendout quantity in units of energy (GJ) is based on heat value measured at each receipt and delivery point location.
(8) True-up relating to the difference between estimated heat value and actual heat value is embedded in Lines 2 to 4

ACCOUNTING TREATMENT FOR AN UNACCOUNTED FOR GAS VARIANCE ACCOUNT (“UAFVA”) – EGD RATE ZONE

The purpose of the UAFVA is to record the cost of gas that is associated with volumetric variances between the actual volume of unaccounted for gas (“UAF”) and the Board approved UAF volumetric forecast.

The gas costs associated with the UAF variance account will be calculated at the end of the fiscal year based on the estimated volumetric variance between the Board approved level and the estimate of the actual UAF. An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UAF and actual UAF.

The UAF annual variance will be allocated on a monthly basis in proportion to actual sales and costed at the monthly PGVA reference price.

Where there are recoveries of gas loss amounts invoiced as part of third party damages, the gas loss amounts will be removed from the UAFVA balance.

Carrying costs for the UAFVA will be calculated using the Board Approved EB-2006-0117 interest rate methodology. The balance of the UAFVA, together with the carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the estimated volumetric variance between the actual UAF and the Board Approved level:

Debit/Credit:	UAFVA	(Account 179. 86_)
Credit/Debit:	Gas Costs	(Account 623. 010)

To record the costs associated with the volumetric variance related to unaccounted for gas.

2. To record the recovery of gas loss amounts:

Debit:	Accounts Receivable	(Account 142. 010)
Credit:	UAFVA	(Account 179. 86_)

To record the recovery of gas loss amounts invoiced as part of third party damages.

3. Interest accrual:

Debit/Credit:	Interest on UAFVA	(Account 179. 87_)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the UAFVA using the Board Approved EB-2006-0117 interest rate methodology.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, including Table 3 and Schedule 3

Preamble:

EGI evidence states: In the EGD Rate Zone, actual UAF was determined to be 256,332 103m3. The forecast UAF volume of UAF was 106,677 103m3. The variance between actual and forecasted UAF volumes of 149,656 103m3, resulted in a debit balance of $41.4 million in the UAFVA, plus interest. Exhibit D, Tab 1, Schedule 3 provides the detailed calculations of the UAFVA balance.

We would like to understand the derivation of the debit balance, the process for replacing and the ratepayer impacts.

Question(s):

Please describe the process undertaken by EGI to replace the unaccounted for gas including:

a) Identification of deficiency

b) Approach to purchasing additional volumes to replace.

c) Reconciliation of inventory balance for company purchased gas (purchases vs. sendout) and where actual consumption is reconciled.

d) Please provide the 2022 monthly purchases of volumes and the cost of those volumes to replace unaccounted for gas.

Response:

a) The identification of a variance to forecasted UFG volumes is completed monthly when comparing forecasted and actual UFG volumes. Please refer to Exhibit D, Tab 1, pages 13 to 19, which describes the processes for the determination of the forecasted and actual UFG volumes.

b) Enbridge Gas monitors the EGD Rate Zone actual and projected storage inventory position as compared to the Gas Supply Plan storage targets at least monthly. Based on the results of this analysis, Enbridge Gas may increase or decrease its planned purchases as required to meet the storage targets. Fluctuations in the actual and projected storage inventory position are driven by many different supply and demand forecast variances, including UAF. For this reason, it is impossible to differentiate specific purchasing activity driven by UAF forecast variances from all other demand and supply variances experienced month to month. To assign a cost to UAF each month, Enbridge Gas uses the applicable PGVA Reference Price.

c) Gas commodity purchases bought to serve Enbridge Gas's franchise customers are recorded as an increase in the inventory balance each month. Actual consumption that includes billed consumption and unbilled consumption is recorded as a reduction in the gas inventory. UFG is the difference between the sendout and actual consumption. When the sendout is higher than the consumption resulting with a loss in UFG, the associated UFG volume is relieved from the gas inventory. Conversely, when the sendout is lower than the consumption resulting with a gain in UFG, the associated UFG volume increases the gas inventory.

d) See the response to part b) above.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, including Table 3 and Schedule 3

Preamble:

EGI evidence states: In the EGD Rate Zone, actual UAF was determined to be 256,332 10^3m^3. The forecast UAF volume of UAF was 106,677 10^3m^3. The variance between actual and forecasted UAF volumes of 149,656 10^3m^3, resulted in a debit balance of $41.4 million in the UAFVA, plus interest. Exhibit D, Tab 1, Schedule 3 provides the detailed calculations of the UAFVA balance.

We would like to understand better the impact of the year-end true-up as it pertains to the period of calendar 2021.

Question(s):

Please provide the before and after true-up volumes for December 2021 and January 2022.

a) Please provide the determination of the before and after UFG volumes for 2021 and any impacts on 2022.

Response:

Please see Table 1, for the true-up volumes as well as the estimated and final UFG volumes for 2021 and 2022 for the EGD Rate Zone.

Table 1

True-up Volumes and Adjusted UAF Volumes for EGD Rate Zone

Line No.	Particulars (10^3m^3)	2021	2022
1	Estimated UAF Volumes	103,646	299,834
2	Estimation Variance for Prior Year	(16,311)	(28,218)
3	Estimation Variance for Current Year	28,218	(15,283)
4	UAF Volumes Adjusted for Estimation Variances	115,553	256,333

Notes:

(1) Line 4 = Line 1 + Line 2 + Line 3

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, including Table 3 and Schedule 3

Preamble:

EGI evidence states: *In the EGD Rate Zone, actual UAF was determined to be 256,332 10^3m^3. The forecast UAF volume of UAF was 106,677 10^3m^3. The variance between actual and forecasted UAF volumes of 149,656 10^3m^3, resulted in a debit balance of $41.4 million in the UAFVA, plus interest. Exhibit D, Tab 1, Schedule 3 provides the detailed calculations of the UAFVA balance.*

We would like to understand better the impact of the year-end true-up as it pertains to the period of calendar 2021.

Question(s):

Did EGI perform a similar true-up for December 2022 using actuals for January 2023.

a) If not, why not?

b) If so, please provide the before and after volumes for December 2022 and the resulting UFG.

Response:

Please see response at Exhibit I.FRPO.18.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, including Table 3 and Schedule 3

Preamble:

EGI evidence states: *In the EGD Rate Zone, actual UAF was determined to be 256,332* 10^3m^3*. The forecast UAF volume of UAF was 106,677* 10^3m^3*. The variance between actual and forecasted UAF volumes of 149,656* 10^3m^3*, resulted in a debit balance of $41.4 million in the UAFVA, plus interest. Exhibit D, Tab 1, Schedule 3 provides the detailed calculations of the UAFVA balance.*

Question(s):

On page 21, EGI describes the establishment of a discrete team with the express mandate to investigate root causes, make recommendations to reduce and monitor, and to implement a sustainment and governance model for UFG for the utility.

a) Please provide the terms of reference or scoping document for the formation of the discrete team.

b) Please provide all reports, summaries and analysis created by the team.

Response:

Please see the response to Exhibit I.STAFF.6.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 2

Preamble:

We would like to understand the source of the substantial increase in Transportation Optimization evidenced in Schedule 2.

Question(s):

For both 2021 and 2022, please provide a monthly report showing the top 4 paths that were optimized showing the monthly revenue generated for each path.

Response:

The top 4 paths for 2022 Transportation Optimization were Dawn to Waddington, Chicago to Dawn, Dawn to EDA and Dawn to East Hereford. The primary reason for the increase in 2022 revenue over 2021 is due to the Dawn to Waddington path. During 2022, there were a number of factors that increased the price of gas at Waddington, and thus, the revenue from optimization between Dawn and Waddington:

- Demand continues to grow in the US Northeast but there has been no increase in the amount of new pipeline capacity into the area.
- Due to the lack of transportation capacity in the area, the other alternative source of peaking supply in the Northeast is imported LNG. During 2022 the price of LNG rose to very high levels due to the Russia-Ukraine conflict and the increased demand for LNG by European countries who were no longer relying on Russian supplied gas.
- During January 2022, there was very cold weather in the US Northeast that drove up the price of gas at Waddington for a number of days.

Tables 1 and 2 below provide 2021 and 2022 monthly revenue for Transportation Optimization by path. The path level detail has been provided on a best-efforts basis.

Table 1

2021 Monthly Transportation Optimization Revenue for Top 4 Paths

Line No.	Particulars ($000's)	Dawn-Waddington	Chicago-Dawn	Dawn-EDA	Dawn-NBJ
		(a)	(b)	(c)	(d)
1	January	2,665.2	131.6	48.4	185.3
2	February	3,145.7	123.7	114.3	6.6
3	March	1,874.9	123.3	63.3	63.6
4	April	17.3	21.4	38.6	0.0
5	May	23.1	47.8	82.5	0.0
6	June	206.5	57.7	192.9	0.0
7	July	92.6	50.4	98.5	0.0
8	August	175.4	54.1	120.9	0.0
9	September	15.5	31.3	53.4	0.0
10	October	20.6	52.0	89.3	0.0
11	November	2,491.7	543.5	21.1	40.0
12	December	2,583.0	573.0	28.5	74.1
13	Total	13,311.5	1,809.9	951.6	369.6

Table 2

2022 Monthly Transportation Optimization Revenue for Top 4 Paths

Line No.	Particulars ($000's)	Dawn-Waddington	Chicago-Dawn	Dawn-EDA	Dawn-East Hereford
		(a)	(b)	(c)	(d)
1	January	11,087.2	314.3	336.8	69.3
2	February	7,133.0	283.9	42.0	277.3
3	March	2,680.2	435.2	61.4	78.7
4	April	289.3	93.6	53.0	0.0
5	May	201.5	96.7	28.1	0.0
6	June	181.9	93.6	33.6	0.0
7	July	520.2	96.7	115.2	0.0
8	August	451.6	96.7	87.3	0.0
9	September	59.4	93.6	48.7	0.0
10	October	108.1	96.7	28.2	0.0
11	November	10,442.1	93.6	2.6	0.0
12	December	11,482.3	96.7	10.4	0.0
13	Total	44,636.7	1,891.5	847.3	425.3

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1 including Table 1
And EB-2022-0110 Exhibit E pages 38 and 39
and EB-2022-0110 Exhibit I.FRPO.19

Preamble:

We would like to understand the reconciliation of Customer Supplied Fuel (CSF) as it pertains to appropriate cost allocation between

In the first reference, Footnote 2 of Table 1 states: UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of CSF.

Question(s):

Please provide EGI's reconciliation of CSF (customer supplied fuel) by showing the activity based UFG for those customers and the amount provided by those customers for 2022.

Response:

Table 1 provides a reconciliation of the UFG Price Deferral Account balance broken down by Utility Supplied Fuel vs Customer Supplied Fuel.

Table 1

Allocation 2022 UFG Price Deferral Account Balance

Line No.	Particulars	Utility Supplied Fuel	Customer Supplied Fuel	Total (1)
1	Experienced Utility UFG (10^3m^3) (2)	59,181	159,723	218,904
2	Collected UFG in Kind (10^3m^3)	0	76,700	76,700
3	Total (10^3m^3)	59,181	83,023	142,204
4	2022 UFG Price Deferral Account Balance ($ Millions)(3)	4.07	5.71	9.78

Note:

(1) EB-2023-0092, Exhibit E, Tab 1, page 47, Table 1.

(2) Portion of actual UFG volumes related to utility and customer supplied fuel based on total throughput volumes.

(3) Line 3 applied to the UFG price variance of $68.80 that is listed in EB-2023-0092, Exhibit E, Tab 1, page 47, Table 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1 including Table 1
And EB-2022-0110 Exhibit E pages 38 and 39
and EB-2022-0110 Exhibit I.FRPO.19

Preamble:

In the third reference, we asked about the reconciliation of CSF. The response initiated with: Exhibit E, Tab 1 pages 38 and 39 have been updated as a result of an error in the calculation of the UFG Price Variance account.

We would like to understand this reconciliation more fully.

Question(s):

Please describe the error that is referred to in last year's response.

a) What has been done to reduce the chance of reoccurrence?

Response:

As referenced in EB-2022-0110, Exhibit E, Tab 1, pages 38 and 39 relating to the UFG Price Deferral Account included errors in Line 1 "Experienced Regulated UFG" and Line 2 "UFG Collected through CSF". More specifically:

- Line 1 was corrected to exclude non-utility volumes as well as a correction to Company Use volumes. All updates and adjustments subsequently made are consistent with the methodology historically used to calculate UFG volumes; and
- Line 2 was corrected to calculate CSF based on actual CSF volumes rather than using budgeted CSF ratios

a) Various measures have been taken to reduce the chance of reoccurrence, including updates to process documentation and year-end task checklists, as well as additional training for staff.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1 including Table 1
And EB-2022-0110 Exhibit E pages 38 and 39
and EB-2022-0110 Exhibit I.FRPO.19

Preamble:

In the third reference, we asked about the reconciliation of CSF. The response initiated with: Exhibit E, Tab 1 pages 38 and 39 have been updated as a result of an error in the calculation of the UFG Price Variance account.

We would like to understand this reconciliation more fully.

Question(s):

Table 1 in last year's response shows an under collection of CSF of 91,849 103m3
Please describe fully how that under recovery is recovered or funded.

Response:

The cost associated with the OEB Approved forecast of UFG volumes is included in rates. These costs are recovered as a unit rate or collected in kind through CSF.

The UFG Price Variance Account captures the variance between the average actual monthly price and the applicable OEB-approved reference price applied to the actual UFG volumes purchased on behalf of ratepayers. The actual UFG volumes purchased exclude UFG volumes from rate payers provided in kind through CSF.

To the extent that there is a variance between actual UFG volumes and forecast UFG volumes, the variance is recovered through the UFG Volume Deferral Account from all ratepayers. A variance represents the under recovery/over recovery of UFG costs, both from customers who pay for UFG costs as a unit rate as well as those who pay for UFG in kind through CSF.

Please see Exhibit F, Tab 3, Schedule 3, page 1, lines 23 and 24, which details the allocation of the 2022 Unaccounted for Volume Variance Account and the Unaccounted for Gas Price Variance Account balances for each respective rate class.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2 and EB-2022-0110 Exhibit I.FRPO.21 - .28

Preamble:

EGI evidence states: Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5%. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas's SQR results following an increased number of customer complaints to the OEB after the Company's July 2021 integration of customers to the CIS system. Following the OEB's compliance review, Enbridge Gas shared its mitigation plans with the OEB and proposed SQR targets for 2022, as part of an Assurance of Voluntary Compliance (AVC)1 signed in September 2022. In the MRPM mitigation plan2, Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). For 2022, Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% or 2.5% when accounting for meters that Enbridge Gas could not access.

Question(s):

For each of Legacy UG and EGD in 2022, please provide the percentage of meters with no read for:
a) 4 months
b) 6 months
c) 9 months
d) 12 months

Response:

Enbridge Gas is committed to providing excellent customer service to all customers and has implemented mitigation plans for the performance measures not met in 2021, including MRPM. Table 1 reflects the percentage of gas meters in 2022 with no read for at least the specified periods, inclusive of any non-specified periods. For example, a gas meter that was not read for 5 months will be included in the 4 months measure, however, will not be duplicated in the 6 months measure.

Table 1
% of meters with no read

Line No.	% of meters with no read	Legacy UG	Legacy EGD
1	4 months (a)	5.28%	3.48%
2	6 months (b)	2.25%	1.14%
3	9 months (c)	1.62%	0.54%
4	12 months (d)	0.68%	0.93%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2 and EB-2022-0110 Exhibit I.FRPO.21 - .28

Preamble:

EGI evidence states: Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5%. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas's SQR results following an increased number of customer complaints to the OEB after the Company's July 2021 integration of customers to the CIS system. Following the OEB's compliance review, Enbridge Gas shared its mitigation plans with the OEB and proposed SQR targets for 2022, as part of an Assurance of Voluntary Compliance (AVC)1 signed in September 2022. In the MRPM mitigation plan2, Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). For 2022, Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% or 2.5% when accounting for meters that Enbridge Gas could not access.

Question(s):

For each of Legacy UG and EGD in 2022, what percent of accounts received a zero consumption bill:

a) From January to June
b) From July to December

Response:

As outlined in EB-2022-0110, Exhibit I.FRPO.21, zero consumption on a gas bill would be based on a customer's consumption behaviour, such as seasonal gas use, or in the case where the meter is temporarily locked. Enbridge Gas's billing practice whenever gas consumption is expected and an actual read is not present, is to use an estimated reading for billing. Table 1 reflects the percentage of accounts which received a zero consumption bill in 2022.

Table 1
% of accounts that received a zero consumption bill

Line No.	% of accounts that received a zero consumption bill	Union Gas rate zones	EGD rate zone
1	January to June	1.15%	1.17%
2	July to December	3.67%	3.64%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2 and EB-2022-0110 Exhibit I.FRPO.21 - .28

Preamble:

EGI evidence states: Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5%. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas's SQR results following an increased number of customer complaints to the OEB after the Company's July 2021 integration of customers to the CIS system. Following the OEB's compliance review, Enbridge Gas shared its mitigation plans with the OEB and proposed SQR targets for 2022, as part of an Assurance of Voluntary Compliance (AVC)1 signed in September 2022. In the MRPM mitigation plan2, Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). For 2022, Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% or 2.5% when accounting for meters that Enbridge Gas could not access.

Question(s):

For each of Legacy UG and EGD in 2022, what percent of accounts received an estimated consumption bill:
a) From January to June
b) From July to December

Response:

a - b)

Please see Table 1.

Table 1

% of Accounts with Estimated Meter Read

% of Accounts with estimated meter read	Union Rate Zones	EGD Rate Zones
January to June (2022)	63.13%	58.95%
July to December (2022)	56.75%	56.07%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2 and EB-2022-0110 Exhibit I.FRPO.21 - .28

Preamble:

EGI evidence states: Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5%. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas's SQR results following an increased number of customer complaints to the OEB after the Company's July 2021 integration of customers to the CIS system. Following the OEB's compliance review, Enbridge Gas shared its mitigation plans with the OEB and proposed SQR targets for 2022, as part of an Assurance of Voluntary Compliance (AVC)1 signed in September 2022. In the MRPM mitigation plan2, Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). For 2022, Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% or 2.5% when accounting for meters that Enbridge Gas could not access.

Question(s):

In last year's referenced IRR's, we requested the second part of the year as July to November. Please update the tables in each of FRPO.21 and FRPO.22 using the period July to December.

Response:

As outlined in EB-2022-0110 Exhibit I.FRPO.21, zero consumption on a gas bill would be based on a customer's consumption behaviour, such as seasonal gas use, or in the case where the meter is temporarily locked. Enbridge Gas's billing practice whenever gas consumption is expected and an actual read is not present, is to use an estimated reading for billing. Table 1 reflects the percentage of accounts which received a zero consumption bill from July to December 2021.

Table 1
% of accounts that received a zero consumption bill

% of accounts that received a zero consumption bill	Union Gas rate zones	EGD rate zone
July to December 2021	3.40%	3.97%

As outlined in EB-2022-0110, Exhibit I.FRPO.22, it is normal billing practice that 50% of all customer accounts are billed based on estimated reads. Also, whenever an actual read is not present, an estimated reading will be used for billing purposes. Table 2 reflects the percentage of accounts which received an estimated consumption bill from July to December 2021.

Table 2
% of monthly accounts with an estimated consumption bill

% of monthly accounts with an estimated consumption bill	Union Gas rate zones	EGD rate zone
July to December 2021	66.60%	55.20%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2 and EB-2022-0110 Exhibit I.FRPO.21 - .28

Preamble:

EGI evidence states: Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5%. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas's SQR results following an increased number of customer complaints to the OEB after the Company's July 2021 integration of customers to the CIS system. Following the OEB's compliance review, Enbridge Gas shared its mitigation plans with the OEB and proposed SQR targets for 2022, as part of an Assurance of Voluntary Compliance (AVC)1 signed in September 2022. In the MRPM mitigation plan2, Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). For 2022, Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% or 2.5% when accounting for meters that Enbridge Gas could not access.

Question(s):

What was the average wait time to get to a live account representative using the customer billing enquiry number 1-877-362-7434 and what is the abandonment rate:

a) From January to June of 2022?
b) From July to December of 2022?

Response:

Enbridge Gas is committed to providing excellent customer service to all customers and has implemented mitigation plans for the performance measures not met in 2021. The results of the mitigation plan were observed with progressive monthly improvements throughout 2022.

a) Average wait time to get a live account representative in 2022 from January to June was 352 seconds or 5.87 minutes. The abandonment rate during the same period was 12.66%.

b) Average wait time to get a live account representative in 2022 from July to December was 45 seconds or 0.75 minutes. The abandonment rate during the same period was 1.69%.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2 and EB-2022-0110 Exhibit I.FRPO.21 - .28

Preamble:

EGI evidence states: Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5%. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas's SQR results following an increased number of customer complaints to the OEB after the Company's July 2021 integration of customers to the CIS system. Following the OEB's compliance review, Enbridge Gas shared its mitigation plans with the OEB and proposed SQR targets for 2022, as part of an Assurance of Voluntary Compliance (AVC)1 signed in September 2022. In the MRPM mitigation plan2, Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). For 2022, Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% or 2.5% when accounting for meters that Enbridge Gas could not access.

Question(s):

In last year's referenced IRR's, we requested the second part of the year as July to November. Please update the responses of FRPO.27 using the period July to December.

Response:

For the period July to December 2021, the average wait time to get a live account representative was 646 seconds (10.76 mins). The abandonment rate during the same period was 23.12%.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2 and EB-2022-0110 Exhibit I.FRPO.21 - .28

Preamble:

EGI evidence states: Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5%. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas's SQR results following an increased number of customer complaints to the OEB after the Company's July 2021 integration of customers to the CIS system. Following the OEB's compliance review, Enbridge Gas shared its mitigation plans with the OEB and proposed SQR targets for 2022, as part of an Assurance of Voluntary Compliance (AVC)1 signed in September 2022. In the MRPM mitigation plan2, Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). For 2022, Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% or 2.5% when accounting for meters that Enbridge Gas could not access.

Question(s):

If EGI chooses to write-off a customer bill for reasonable purposes (e.g., no ability to recover bill due customer relocation, etc.), does the revenue amount get charged to Bad Debt/Miscellaneous O&M) or other? Please explain fully including what adjustments are made to remove the unrecovered gas quantity from the UAFVA calculations.

a) Does the same process occur for all bad debt related gas quantities? Please explain fully.
b) Please provide the total Bad Debt, the amount of gas associated with that expense for each month of 2022.

Response:

If Enbridge Gas chooses to write-off a customer bill, the accounts receivable balance is charged to bad debt expense. There is no adjustment in the UAFVA calculations for write-offs to bad debt.

a) Confirmed, the same process described above occurs for all bad debt related gas quantities.

b) Please see Table 1 below for 2022 Bad Debt expense by month. The amount of gas associated with the monthly bad debt expense is not available, as bad debt expense is recorded based on dollars and not gas volumes. Bad debt expense includes all types of balances and charges, including charges that are not associated with gas volumes, such as fixed monthly customer charges. As such, gas volumes associated with bad debt expense is not available.

Table 1
2022 Bad Debt Expense by Month

Line No.	Particulars ($ millions)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Bad Debt Expense	1.8	1.7	4.8	1.8	1.5	-1.6	0.7	0.7	5.1	0.8	-3.3	1.4	15.4
2	Total	1.8	1.7	4.8	1.8	1.5	-1.6	0.7	0.7	5.1	0.8	-3.3	1.4	15.4

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2 and EB-2022-0110 Exhibit I.FRPO.21 - .28

Preamble:

EGI evidence states: Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5%. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas's SQR results following an increased number of customer complaints to the OEB after the Company's July 2021 integration of customers to the CIS system. Following the OEB's compliance review, Enbridge Gas shared its mitigation plans with the OEB and proposed SQR targets for 2022, as part of an Assurance of Voluntary Compliance (AVC)1 signed in September 2022. In the MRPM mitigation plan2, Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). For 2022, Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% or 2.5% when accounting for meters that Enbridge Gas could not access.

Question(s):

Please provide the respective amounts invested in the meter read, billing and customer accounting for EGI:
a) Using 2020 actual costs
b) Using 2021 actual costs
c) Using 2022 actual costs

Response:

When compiling this response, Enbridge Gas discovered that the response provided in EB-2022-0110 Exhibit I.FRPO.28 was incorrect for the 2020 and 2021 actual costs for meter read, billing and customer accounting. These amounts have been corrected and provided in Tables 1 to 3.

Total costs for Enbridge Gas are summarized below.

Table 1 shows meter reading costs for Enbridge Gas.

Table 1
Meter Reading Costs

Line No.	Particulars ($ millions)	2020 Actual (a)	2021 Actual (b)	2022 Actual (c)
1	Total EGI	17.2	18.5	20.1

Table 2 shows bill production costs for Enbridge Gas.

Table 2
Bill Production Costs

Line No.	Particulars ($ millions)	2020 Actual (a)	2021 Actual (b)	2022 Actual (c)
1	Total EGI	3.9	4.0	4.1

Table 3 shows customer accounting/receivables costs for cheque payment processing for Enbridge Gas. All other forms of payment are electronic, and the costs are not reflected in the table because they are not part of Customer Care O&M costs.

Table 3
Customer Accounting/Receivables Costs

Line No.	Particulars ($ millions)	2020 Actual (a)	2021 Actual (b)	2022 Actual (c)
1	Total EGI	0.7	0.5	0.4

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers (OGVG)

Interrogatory

Reference:

Exhibit B Tab 3 Schedule 1 Page 3

Preamble:

CSS costs were $67.1 million higher than the prior year primarily due to: a higher share price and stronger Enbridge Inc. performance that has resulted in higher LTIP and STIP, higher legislative benefit costs resulting from a year over year change in maximum contribution levels, higher TIS costs related to additional mandated cybersecurity costs and incremental sustainment costs related to the addition of 1.6 million customers to the CIS system in 2021. These variances were partially offset by higher overhead capitalization of CSS costs, lower pension costs and a decrease in insurance premium costs.

Question(s):

a) What were the total LTIP and STIP amounts within the CSS cost category in 2021 and 2022?

b) What would the total LTIP and STIP amounts within the CSS cost category have been in 2022 at the following levels:
   i) Assuming that performance in 2022 had attracted the minimum amount of LTIP and STIP,
   ii) Assuming that performance in 2022 had attracted the "target" amount of LTIP and STIP, and
   iii) Assuming that performance in 2022 had attracted the maximum amount of LTIP and STIP.

c) What were the total LTIP and STIP amounts incurred outside the CSS cost category in 2021 and 2022?

d) What would the total LTIP and STIP amounts outside the CSS cost category have been in 2022 at the following levels:
   i) Assuming that performance in 2022 had attracted the minimum amount of LTIP and STIP,

ii) Assuming that performance in 2022 had attracted the “target” amount of LTIP and STIP, and
iii) Assuming that performance in 2022 had attracted the maximum amount of LTIP and STIP.

Response:

a) Please see Table 1:

Table 1

2021 and 2022 LTIP and STIP

Line No.	Categories	2021	2022
1	CSS STIP	10.7	16.8
2	CSS LTIP	14.3	53.1
3	BU STIP	47.8	37.4
4	BU LTIP	14.1	20.3
5	Total STIP And LTIP	86.9	127.6

Please note Business Unit (BU) or outside the CSS cost category are Enbridge Gas direct employees.

b-d)

Please see Table 2 for the target and maximum STIP for CSS and BU (outside the CSS category). Please note the calculation is for illustrative purposes only with high level calculations and assumptions due to the fact STIP numbers presented in Table 1 consists of STIP payout of all Enbridge Gas employees and it is not reasonable to recalculate the STIP amount for each individual employee.

Unlike STIP, LTIP is not based on annual metrics impacted by minimum, target and maximum levels as this component of the compensation program is based on the achievement of Enbridge Gas’s long-term goals or strategic objectives consisting of stock option and share unit plans. Please refer to Exhibit I.EP.3 for further details of the LTIP program. The payout can take several years to realize and the benefit amount is driven by the share price.

Table 2
Minimum, Target, Maximum STIP

Line No.	Categories	2022
1	CSS STIP(minimum)	0.0
2	BU STIP(minimum)	0.0
3	CSS STIP(target)	13.0
4	BU STIP(target)	29.7
5	CSS STIP(Maximum)	25.9
6	BU STIP(Maximum)	59.4